U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No. 50-397/87-19

Docket No. 50-397

License No. NPF-21

Licensee: Washington Public Power Supply System
P. O. Box 968
Richland, Washington 99352

Facility Name: Washington Nuclear Project No. 2 (WNP-2)

Inspection at: WNP-2 Site, Benton County, Washington and WPPSS Engineering Offices, Richland, Washington

Inspection conducted: August 3, 1987 through August 28, 1987

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Summary:

Inspection on August 3 through 28, 1987 (Report No. 50-397/87-19)

Inspection Objective:

The objective of this inspection was to assess the operational readiness of selected safety systems at WNP-2.

Inspection Method: A Safety System Functional Inspection (SSFI) was performed on selected safety systems. An SSFI type inspection is a design based inspection process. One of the chief advantages of this type of inspection is that it concentrates a comprehensive, multi-discipline review into a relatively narrowly defined area. The intent of the inspection is to define an inspection area that is not only important to plant safety or accident mitigation, but to select an area involving a broad cross-section of activities by the various disciplines in the licensee organization. This type of approach allows the inspectors to develop a fairly accurate perspective of how well the licensee organization integrates the various aspects of plant design, engineering, operation, maintenance, etc. Recent experience with this type of inspection has shown it to be effective at pointing out deficiencies both in the area of adequate licensee understanding of the design basis for the plant and in the area of control of the design process.

Basis and Scope of Inspection:

In defining the scope of this inspection, the NRC adapted generic PRA data to the specific WNP-2 plant design in order to determine significant plant failure modes. Recent NRC findings relating to engineering and quality assurance problems (e.g. root cause assessment) were also considered. This review process resulted in the selection of the AC and DC electric power distribution systems as the primary areas of emphasis for the inspection. The inspection scope also included the Standby Service Water System (a significant emergency power support system) and the Automatic Depressurization System (a significant accident mitigating system in the event of a loss of power event).

Results of the Inspection:

Major Concerns Identified

1. Inadequate Control of Plant Design Requirements

The team noted several examples of problems in which the licensee appeared to have lost control of the plant design process. Specific concerns in this regard involve both a lack of licensee understanding of the plant design basis and a loss of control of implementation of design requirements into plant modifications and procedures. In addition, the types of problems noted raises a concern as to the adequacy of quality assurance controls in the deficient areas.

2. Plant Material Condition and Housekeeping Deficiencies

The team observed several examples of plant material condition and plant housekeeping deficiencies.

3. Inadequate Root Cause Assessment and Corrective Action

The team identified some instances in which it did not appear that the licensee had implemented aggressive root cause assessment or timely corrective action following specific plant malfunctions.

A more detailed summary of the team findings is provided as Appendix B to the transmittal letter accompanying this inspection report.

Summary of Violations Identified

Of the areas inspected, ten apparent violations of NRC requirements were identified, as summarized below:

A. Failure to comply with requirements for establishing, implementing and maintaining procedures for the surveillance and testing of safety related equipment.

B. Failure to comply with Technical Specification requirements for minimum fuel oil supply for emergency diesel generators.

C. Failure to properly implement quality assurance program requirements for compliance with station procedures.

D. Failure to comply with Technical Specification requirements for obtaining review and approval of station procedure changes.

E. Failure to comply with requirements for periodic testing of safety related time delay relays.

It should be noted that several areas of potential violation of NRC requirements remain unresolved, pending completion of additional licensee review of the specific problems involved. Further actions in this regard will be the subject of future correspondence, following review of additional licensee information on these items.

DETAILS

1. Persons Contacted

Licensee personnel attending the exit meeting on August 28, 1987 included:

S. S. Allen, Engineer I, Fire Protection
J. W. Baker, Assistant Plant Manager
G. Brastad, Technical Specialist (Electrical/I&C)
J. P. Burn, Director of Engineering
S. Chaudhuri, Principal Electrical Engineer
J. Civay, Principal Electrical Engineer
J. D. Cooper, Principal Engineer, Maintenance
C. D. Eggen, Principal Engineer, Fire Protection
C. J. Foley, Technical Specialist
G. Freeman, Principal Test Engineer
F. D. Frisch, Principal Engineer, Operations
P. W. Harness, Technical Specialist
L. T. Harrold, Manager, Generation Engineering
D. A. Injerd, Engineer I, Mechanical Systems
W. M. Kelso, Principal Engineer
R. Koenigs, Supervisor Plant Engineering
G. Lawrence, Principal Electrical Engineer
J. Massey, Supervisor Electrical Maintenance
R. Matthews, Principal Electrical Engineer
G. Moore, Senior Electrical Engineer
J. C. Mowery, Principal Engineer
D. M. Myers, Principal Engineer
B. D. Ngo, Engineer I, Mechanical Systems
C. R. Noyes, Manager, Mechanical Systems
N. Porter, Manager, Electrical/I & C Systems
C. M. Powers, Plant Manager
M. Rice, I & C Engineer (Diesel Generator)
D. Thorn, Principal Electrical Engineer
S. N. True, Clerk, Records Management
A. Warren, Nuclear Plant Engineer (DC Systems)
C. M. Whitcomb, Leader, Technical Program
D. L. Whitcomb, Technical Specialist
S. G. Willman, Engineer I

In addition to the individuals identified above, various other engineering, quality assurance, maintenance, and operations personnel and other members of the licensee's staff were interviewed during the inspection.

For the NRC, J. B. Martin and R. P. Zimmerman of Region V, the NRC licensing project manager, and the resident inspector, attended the exit meeting, in addition to the inspection team members.

2. Plant Engineering and Design Modification

Plant engineering and design modifications were reviewed in the mechanical, electrical, instrumentation and controls, HVAC, and fire protection disciplines. The review focused on the Emergency Electrical Systems (both ac and dc) and their support systems. These included the emergency Diesel Generators and their auxiliaries, the AC and DC Electrical Distribution Systems, the Standby Service Water System, the 125 VDC and 250 VDC Batteries and their associated hardware, the essential HVAC for these systems, and the fire protection for these systems. In addition, the Automatic Depressurization System and its support systems were reviewed. The team findings in this area are summarized in the following sub-paragraphs:

a. Class 1E Battery Sizing

The Division 1 and Division 2 125 volt batteries and the Division 2 250 volt battery were replaced in 1983 with different type Exide cells than used in the original batteries. The common battery sizing calculation (Calculation No. 2.05.01, Revision 6, 3/5/84) was revised to address the new 125 volt cells only. The team reviewed the battery sizing calculation and had the following concerns.

The data documentation used to develop the load profile was deficient in that many of the inputs, such as dc motor loads, switchgear control, and demand and diversity factors, were not sufficiently referenced to permit verification. The team attempted to duplicate the loads on the Class 1E battery profiles and found problems in both the 125 volt and 250 volt profiles reviewed. The 250 volt Division 1 battery motor loads used in the calculation did not agree with the dc single line drawing (Drawing No. E505, Revision 41, 7/21/86). Additionally, the motor starting currents were assumed in the calculation to be limited to 200% full load current, however, the team found that the calculation (Calculation No. 2.05.08, Revision 1, 7/21/83) which sized the starting resistors, permitted a motor starting current of 300%. This inconsistency alone could account for an additional profile load of over 300 amperes in the first minute on the 250 volt battery. Additional errors noted by the team were associated with both the 250 volt and the 125 volt safety-related inverter loads, including corrections to battery loading for inverter dc input voltages at less than nominal voltage and decreased inverter efficiency at less than rated load.

The team also identified problems with the methodology used in the calculation. The calculation was performed looking only at the total length of battery discharge and failed to consider the incremental effect of each step in the load profile. This was most significant in the 125 volt Division 1 battery in which the licensee's calculation concluded that a cell with only 2 positive plates would provide adequate margin. In fact, based solely on the original profile, the team calculated that a cell with 6 positive plates would be required to maintain the battery voltage above 105 volts during this initial transient. The methodology for this type

calculation was published by EXIDE as early as 1954 with HOXIE'S AIEE paper, "Some Discharge Characteristics of Lead Acid Batteries". This paper formed the basis for IEEE-485, Recommended Practice for Sizing Large Lead Acid Storage Batteries. In addition, the calculation failed to account for the degraded battery conditions permitted by the plant technical specifications (Technical Specification 4.8.2.1) and should have included correction factors for the minimum permitted operating temperature of 60 degrees F, aging, and maintenance margins. If all these margins were included in the original load profile, as recommended by current industry standards (IEEE 485-1978 and 1983), both the existing 125 volt and 250 volt Division 1 batteries would appear to be undersized. Only because these batteries are relatively new and tested capacity shows these batteries have greater than rated capacity, does the team believe that this is not an immediate safety concern.

The Division 3 battery was modified to a 58 cell battery by design change PMR-2-85-0181-0. The sizing for this battery is documented by Supply System calculation no. E/I 02-85-02, Revision 0, 5/3/85. The load profile for this calculation is based upon the Final Safety Analysis Report (FSAR) load Table 8, 3-6. The calculation did not attempt to confirm these FSAR loads. Similar to Division 1, the team found a problem with the motor starting current assumed for the diesel standby fuel pump. The FSAR table assumed the starting current was limited to 10 amperes (200% of full load current). However, the motor test record indicated the starting current could exceed 20 amperes.

In addition, while the calculation included margins for minimum temperature, aging, and design margin, the team found that the correction factor for minimum temperature was based upon 65 degrees F, not the allowable 60 degrees F minimum temperature. Corrections for these errors would require a battery cell with 5 positive plates to permit battery replacement at 80% rated capacity. The present Division 3 cells contain only 4 positive plates and the latest battery performance test dated 4/18/87 revealed that the battery has already degraded to 88.35% capacity. The team is concerned that little margin remains in this battery.

Failure to assure that the design basis for the safety-related batteries was correctly translated into station documents appears to be a violation of 10 CFR 50 Appendix B, Criterion III. This item remains unresolved, pending additional licensee evaluation (50-397/87-19-01).

b. <u>DC System Minimum Voltage</u>

The team reviewed voltage drop calculations (Calculation Series 2.06.xx) for voltage drops from motor control centers to their associated loads.

(1) The team selected Calculation No. 2.06.04, Revision 13, dated 3/11/87, to review the Division 1, 125 volt dc motor operated valve (MOV) supply cable voltage drop determination. The team

observed that the calculation correctly stated the requirement that the voltage drop calculations for dc motor operated valves must consider four (4) times the one-way distance to the valve in order to account for the reversal of the current through the armature windings required to change valve direction. The team noted, however, that the voltage drop calculation for many of the valves did not consider this assumption. The team was informed by the licensee that instead of including four times the length of cable run in the calculation, the conductors were paralleled to reduce the conductor resistance in half. During this review, the team learned that the parallel conductors, which were in fact identified in the calculation by noting a cable construction of 9 conductors versus the original 5 conductors, were never installed. The team was informed that the reason the additional conductors had not been installed in the DC MOV circuits was that the Startup organization had performed a test which was intended to demonstrate that sufficient voltage would exist at the valves without the parallel conductors. As a result of this test, the design modification was voided. The team found the test results recorded in PED-S218-E-C640 deficient for the following reasons:

(a) Bus voltage was measured to be varying between 125 and 135 volts during the test, indicating that other factors were affecting the recorded voltage measurements.

(b) The valves did not appear to be under design load conditions when tested.

(c) Starting currents were not considered in a majority of the valves tested. The combined starting currents of the valves could significantly reduce the terminal voltage available at the valves.

(d) Test results recorded for the valves in question did not include valve CAC-V-8.

The team observed that the calculation assumed a total allowable drop from battery to load of only 4% (125V x .04 = 5 volts). This criteria was contained in the calculation apparently to account for the worst case voltage degradation during battery discharge (105 volts - 5 volts drop = 100 volts at the loads). However, neither this calculation, nor Calculation No. 2.07.04, Revision 3, 7/6/83, which was to account for the 1% drop between the battery and the MCC, considered the voltage drop in the cabling during transient conditions including motor starting. This initial total voltage drop should be considered to confirm the adequacy of the voltage at the valves at the time the valves first start to stroke. Based upon the WNP-2 original battery load profile, the team estimated the battery voltage at degraded conditions during a battery discharge and concluded that the starting voltage at five of the 125 volt dc motor operated valves in

Division 1 would drop below the specified minimum starting voltage of 100 volts. The voltage drop from the battery to the MCC could account for an additional 8% voltage drop under worst case conditions. This is an apparent violation of 10 CFR 50, Appendix B, Criterion V (50-397/87-19-02).

(2) The team also noted that no voltage drop calculations had been performed for the safety-related inverter dc supply or for the 125 volt switchgear control circuits. The team estimated, based on the original load profile, that the voltage at the inverters and certain safety-related 4kV switchgear control circuits could fall below the manufacturer's rated minimum voltage of 105 volts. While the team believes that margin exists below the published Westinghouse rated minimum voltage of 105 volts (Application Data 32-262, Type DH-P air circuit breakers) for the close coils, the safety-related inverter manufacturer's (Elgar) instruction manual (Inv 203-101) states that the inverter will automatically shutdown when the battery is discharged to 105 volts.

It is the teams understanding that, in response to this inspection, the licensee has performed preliminary voltage calculations, based upon a new load profile, which will demonstrate adequate voltage at these components. This is an open item (50-397/87-19-03).

c. Motor Operated Valve Overload Selection

The team reviewed the overload protection provided for a number of the service water valves required to support the diesel generator. The majority of the associated motor control centers were manufactured by ITE and use 3 single phase overload relays to protect their motor loads. The team found that overload heaters were selected to trip the valve motors based upon Burns and Roe technical memorandum T.M. No. 1129, dated 8/11/78. This document implied that if the overload heaters were selected at 140% of motor full load current, sufficient locked rotor current protection would result. No supporting documentation could be found by the licensee at the time of the inspection to support this conclusion.

The failure to confirm the assumption that thermal overload relays selected at 140% of motor full load current would provide adequate protection for short time duty motor operated valves appears to be a violation of 10 CFR 50 Appendix B, Criterion III. This item remains unresolved, pending additional licensee evaluation. (50-397/87-19-04).

The team independently sized overload protection for these valves based upon the valve actuator manufacturer's recommendation, obtained from the licensee, as presented in IEEE technical paper F79669-3, dated 5/1/79. This document recommended that for short time duty motors used on motor operators, the locked rotor current time should be limited to 10 to 15 seconds in order to protect the motor windings from thermal damage. With the overload heaters

selected by the licensee at 140% of full load current, no running protection and insufficient locked rotor protection would result.

The team determined that at locked rotor current, the heaters would require approximately one minute to actuate.

The team estimated, based upon a review of valves SW-V-2A, 2B, 4A and 4B, that overload heaters six sizes smaller than presently installed would provide both running and locked rotor protection and still provide at least 700% margin on valve stroke time at motor full load current. An overload heater size smaller would still provide 200% margin on full load current at rated valve stroke time. Other valves checked by the team produced similar results.

In addition to the above, the team found that most of the valves in the RHR system and some valves in other systems appeared to have the B phase overload heater wired for alarm only and not to trip the breaker. However, these heaters, used for alarm purposes only, were also found to be selected by the same original TM 1129 criteria so that the alarm would not be received prior to motor damage.

In contrast, the team found that the overloads provided on a GE motor control center (MC4A) included a three phase overload relay to trip on motor overload and a single phase overload relay with a smaller heater to alarm on a smaller overload. However, the licensee had elected not to wire these alarm relays to take advantage of the early alarm feature. The team was not able to confirm the adequacy of these GE overload relays during the inspection because of time constraints.

d. Engineering and Design Modification

The methods and instructions for the identification, control, implementation, documentation and closeout of plant modifications is addressed in Administrative Procedure No. 1.4.1, "Plant Modifications," Revision 6, of April 17, 1987. This procedure describes activities to ensure that plant modifications properly implement plant design changes. The program, in part, requires the proposed plant modification to be described in a Design Change Package (DCP) which, when approved, is implemented by a Material Work Request resulting from initiation of a Plant Modification Record (PMR). The PMR, therefore, is the controlling document because it identifies the plant modification to be performed, including the MWRs; it provides authorization for implementation; and requires verification that the installation is complete and the system operable. Review of the plant modification procedure by the team indicated that the program does not contain provisions addressing partial implementation of design modifications. The concern expressed by the team was that if, due to unforeseen circumstances, a modification is partially implemented, there are no procedures to describe what actions to take to ensure that the partial implementation is acceptable. Discussions with licensee management personnel involved with outage scheduling and

implementation of work authorized by PMRs concurred with this observation. Their position was essentially that their procedures do not allow partial implementation of design changes.

The team reviewed the records of DCPs processed over the past several years looking for design modifications involving more than one DCP or multi-disciplined groups. The team also interviewed licensee engineering personnel regarding implementation of design changes. This effort revealed a discrepancy regarding a plant design modification covered by DCP 84-1096-OA and OB and approved for implementation in September 1984. This modification installed two new safety-related auxiliary steam isolation valves (OA) and missile shielding for these valves (OB). Each of the design packages (OA and OB) required that both DCPs be completed in order to consider either DCP to be complete. Both PMRs written to implement the DCPs were signed off as complete and design drawings were revised in July 1985 to show the additional valves and shielding. However, when the team reviewed the completed installations, it was observed that the shielding was not installed. Subsequent review of the modification package revealed that the field work was never specified on a MWR and therefore not implemented. The licensee initiated NCR No. 287-297 to document this problem. The team reviewed the modification program and concluded that had the responsible Technical Engineers followed their procedure, this problem would not have occurred. Specifically, the procedure in effect in June 1985 was Revision 2 of Procedure No. 1.4.1. Section 1.4.1.6 required the Plant System Engineer to initiate the MWRs to implement the change. The MWRs for the missile shielding were not prepared. Attachment 1, the PMR form, Block 18 required the signature and date of the Plant System Engineer indicating that the installation of the modification was complete. Although Block 18 was signed off as complete, the work was never initiated. These events led up to the Shift Manager reviewing a supposedly complete PMR package and signing off that the system is considered operable, thus returning the system to service.

Failure to install the missile shield as required by the Plant Modifications procedure is an apparent violation of 10 CFR 50 Appendix B, Criterion V (50-397/87-19-05).

The inspectors' evaluation into the probable root cause of this problem identified two weaknesses in the current modification program as addressed in Procedure 1.4.1. First, there are no provisions to assure the MWRs are initiated covering the entire scope of a modification. Second, there are no specific requirements assuring that the entire scope of a modification was actually implemented. The inspector discussed this with the Plant Technical staff which resulted in the licensee initiating a Procedure Deviation to revise Procedure 1.4.1 to include these provisions. The inspector reviewed the proposed revision and recommended that the licensee consider including a joint verification as-built walkdown of completed DCPs by the Plant Technical and Design Engineering groups. Although no commitment was made on this matter, during the exit meeting, the licensee did respond favorably to the idea.

Other examples of PMR signoffs indicating completion of a modification when, in fact, the entire work was not completed are: (a) NCR No. 287-294 written on August 14, 1987, identifying that two pipe supports, DSA-4275-12 and 13, to be installed during the April 1986 outage, were not installed. As a result, this system was declared operable without justification that failure would not occur. However, justification was obtained from the design engineering group on August 14, 1987, stating that no actual failure of the line would occur had a seismic event occurred; (b) standby service water valves SWS-PCV-38A and 38B were modified to eliminate automatic pressure control and valve position indication (VPI) in the control room, and (c) condensate valves COND-V-9A and 9B were also modified to eliminate VPI in the control room. In examples (b) and (c), instrumentation and controls in the control room did not provide indication, as required on the MWRs, that their related systems have been retired. How the licensee plans on addressing the issue of partial implementation and partial justification for declaring an effective system operable is an open item. (50-397/87-19-06).

e. Fire Protection Systems for Diesel Generators

WNP-2 is equipped with three diesel generators, Division 1 and Division 2 units which supply onsite emergency AC power for the two basic trains of ECCS equipment, and the Division 3 unit which supplies onsite emergency AC power for the HPCS pump only. They are located in separate rooms of one building, these rooms having 3-hour fire rated walls and doors. Each room has two access points, one to the south opening to the outside and another to the north opening into a common hallway. The doors open outward away from the room. The north doors are equipped with a curb approximately 3 1/4 inches high; the south doors have no curb.

Fire protection is provided in the rooms by a pre-action sprinkler system with fusible sprinkler heads. Drainage for the rooms is through several floor drains in each room connecting to a common six inch line in the Division 1 and 2 rooms and a common four inch line in the Division 3 room. These drains are capable of carrying only a limited flow from the sprinklers.

The fuel oil transfer pumps for all three divisions are located in three separate rooms adjacent to the Division 3, HPCS diesel generator room. The only entrances to these rooms are from the HPCS diesel generator room. They are also protected by pre-action sprinklers. No drains are provided for these rooms.

The design of the diesel generators and the associated systems and components is governed by several codes, standards, and regulatory documents, which specifically address the fire protection requirements and the separation and redundancy requirements. These include 10 CFR 50, Appendix A; and NRC Branch Technical Position APCSB 9.5-1.

In response to these requirements, the licensee made the following commitments in the FSAR:

- FSAR, Appendix F, Fire Protection Evaluation, Amendment No. 37 dated August 1986, response to Branch Technical Position APCSB 9.5-1, NRC Position D1(a), states "All Appendix R safety-related systems have been separated from unacceptable fire hazards through remote separation or fire barriers to the extent that is possible."

- FSAR response to Position D1(i) states "Actuation of the fixed fire protection system would not adversely affect any safety-related equipment by flooding.

- FSAR response to Position D2(a) states "Safety-related systems have been isolated or separated from combustible materials to the extent possible."

- FSAR, Section 8.3.1.1.8 - Standby AC Power System, Amendment No. 34 dated January 1984, states "Design provisions ensure that flooding in one diesel generator room does not jeopardize the operation of the other diesel generators."

- FSAR, Section 9.5.4.2, Amendment No. 36 dated December 1985, states "Although a single failure may result in loss of fuel to one diesel generator, the other diesel generator can provide sufficient capacity for emergency conditions, including safe shutdown of the reactor, coincident with loss of offsite power."

Several inadequacies were observed by the team in the coordination of the design of the fire protection systems and the floor drainage systems of the diesel generator rooms. These problems are discussed in more detail as follows:

(1) <u>Failure of the Fuel Transfer Pumps</u>

As discussed above, the fuel oil transfer pump rooms for all three emergency diesel generator units are located adjacent to the Division 3 diesel generator room with their only entrances being from this room. The fuel oil transfer pumps are electrically driven and are located in pits in the rooms just above the ends of the main fuel storage tanks. These pits have no curbs around their upper edges and no drains. The rooms have no floor drains. Therefore, any fluid entering the rooms will fill the pits and potentially drown out the pump motors. At the door to each room is a curb approximately 7 5/8" high separating it from the Division 3 diesel generator room.

The primary accident scenario of concern is the single failure of a pump seal or a flexible fuel line on the discharge side of the fuel oil pump on the Division 3 diesel generator followed by a fire in the room. The worst case of this scenario would be when a large amount of oil would be leaked onto the floor

and would spread over a large area before being ignited by some heat source on the engine. In this case the initial fire could be quite large, and many of the sprinkler heads in the room could be fused, causing a high flow rate of water into the room. If the rate of flow into the room exceeded the drainage rate, the level would eventually rise to the point where it would spill over the curbs of the Division 1 and Division 2 transfer pump rooms, at which time both pumps could be incapacitated. Within as little as 5 1/2 hours after this, both Division 1 and Division 2 diesel generators' day tanks would be empty, their engines would stop, and all onsite AC power could potentially be lost. This would be particularly significant if it occurred during a loss of offsite power (loop).

For less severe fires, the number of sprinkler heads fused would be less; therefore, the time until spillover would occur would be longer.

An exacerbating condition is the licensee's use of absorbant pads around the diesel generator units to absorb oil drips. These pads are not secured, and additional pads, wiping rags, and other extraneous material are loosely stored in the rooms. These would tend to be washed to the drains and under the south door early in the event, potentially blocking all drainage.

The licensee was asked if there was any analysis which showed that actuation of the fire protection would not flood the room. None was produced, although a quick, on-the-spot, unverified calculation done by the licensee showed that spillover into the fuel oil transfer pump rooms would occur at about 17 minutes after fire initiation assuming no drainage from the room.

The licensee also could produce no evidence that the drains had ever been verified open. This together with the potential for plugging provided by the loose material observed in the rooms strengthens the assumption used in the calculation that no drainage would occur.

The licensee presented a position that the flooding would not likely occur because the site fire brigade would arrive at the scene minutes after the fire started and they would shut off the sprinklers and/or open one or both of the doors to the Division 3 diesel generator room, releasing the water. The team did not consider this to necessarily be a valid response for several reasons: (1) The licensee was apparently not aware of this threat prior to this inspection, and there is no plant procedure which gives any special instructions on how to deal with water in this room. There is therefore, no reason to expect that the fire brigade would take any deliberate action in time to prevent flooding to the critical stage. (2) An argument can be made that, without specific direction to the contrary, a reasonable response of the fire brigade might be to leave the doors shut and allow the sprinklers to perform their

function. This would be particularly true if it were suspected that flooding did exist in the room, since opening of the doors might risk allowing burning oil to move to other areas not previously threatened. And finally (3), even if the fire brigade desires to open the doors, there is no reason to expect that they necessarily could in a timely manner. Flooding pressure against the latches may prevent their being opened normally. Additionally, oil spreading under the doors could also be burning, impeding timely access.

With the scenario described above, as a result of a single credible failure, all three sources of onsite AC electrical power could potentially be lost. This item remains unresolved, pending additional evaluation by the licensee and NRR. (50-397/87-19-07).

(2) Fire Threat to Both Safe Shutdown Divisions

In the common hallway outside the diesel generator rooms are raceways for all three divisions of emergency power with only Division 2 Safe Shutdown cables being fire protected by sprinklers and by being wrapped with a one-hour fire barrier material. Division 2 is the designated Safe Shutdown Division for the plant.

In all three rooms the fire accident scenario described in (1) above also has the potential to spread the hazard outside the 3-hour barrier of the room where the fire has occurred and threaten the other two unprotected divisions of LOCA required cables in the common hallway. The mechanism for this threat is, as described above, flooding of the rooms due to actuation of the sprinkler system. This flooding would cause spillover at the curbs at the north doors, and the liquid would flow under the doors and into the common hallway. Since the oil would tend to float on top of the water, it would be the first liquid to spill over, and therefore, this transient combustible would be in the hallway where it would be a threat to all three divisions of cables. If the fire scenario were to occur in the Division 2 diesel generator room at any time including normal operation, the ability of the plant to achieve safe shutdown could be compromised.

(3) Fire in Division 1 or Division 2 Fuel Oil Transfer Pump Rooms

The diesel fuel transfer pump rooms for the Division 1, Division 2, and Division 3 emergency diesel generators are located adjacent to the Division 3 diesel generator room with their only doors opening from this room. The fuel transfer pumps are located in pits in the rooms, and fire protection is provided by sprinklers. There are no floor drains or other drains in the rooms. At the entrance to each room is a sill approximately eight inches high.

The event of concern here is a fuel oil leak in either the Division 1 or Division 2 fuel transfer pit area being ignited by an electrical spark. In this case, the sprinklers in the room would be activated. Such a fire could occur at any time a transfer pump is running, such as during an engine test, when an operator is topping off an engine day tank in preparation for filling the main storage tank, or during engine response to an event. With activation of the sprinkler system, the pit will fill with water, and after some finite time, if the sprinklers are not secured by the fire brigade, the room will fill to the point that the liquid will spill over the door sill and into the Division 3 diesel generator room. Since oil would be part of the fluid spilling over, the Division 3 equipment could now be threatened by the uncontrolled flammable liquid on the floor.

In this fire scenario, one division of emergency power would be disabled by the initial fire, and a second division, Division 3 could be threatened as a result of this single failure. Although this particular scenario does not prevent achieving safe shutdown from normal plant operations since either Division 1 or Division 2 will not be affected, it does degrade the condition of the plant. Items (2) and (3) above remain unresolved, pending additional review by the licensee and NRR (50-397/87-19-08).

The licensee has agreed to take several corrective actions to alleviate the problems caused by fires in the diesel generator rooms. These include:

- Installation of automatic acting scupper flappers on the south doors of the rooms to allow drainage to the outside.
- Securing or removing all oil soak up pads and other articles capable of plugging the drains in the rooms.
- Verifying the drains to be open and clearing those not found open.
- Training of the fire brigades on the special hazards to plant safety associated with fires in these rooms.

No remedial action has been suggested by the licensee with regard to the hazards associated with fire in the fuel transfer pump rooms.

f. <u>Air Filtration for Emergency Diesel Generator Units</u>

10 CFR 50, Appendix A, Criterion 2, Design Basis for Protection Against Natural Phenomenon requires that systems important to safety shall be designed to withstand the effects of natural phenomenon. One natural phenomenon for which the diesel generator and their support systems as well as other systems in the plant must be designed is particulate matter in the air. Air in large volumes is required for operation of the diesels for both combustion and

ventilation of the spaces, and the particulate matter must be removed to assure reliable operation of the systems. The concentration of matter which must be dealt with ranges from relatively minute during normal conditions, to dust storms which are common in the area, to volcanic ash fallout which is rare but credible in view of the Mt. St. Helens eruption which generated heavy ash fall in close proximity to the plant.

The designs to deal with these conditions consist of oil bath filters for the combustion air for each diesel generator unit for normal operation and design basis dust storms; dry disposable paper filters for the ventilation systems for normal operation and design basis dust storms; and dry disposable paper filters for the design basis ash fall event, which are temporarily installed upstream of and provide common prefilter banks for both the combustion air and ventilation filters for the Division 1 and Division 2 diesel generators.

Abnormal Conditions Procedure 4.12.4.5, Design Basis Ash Fallout, requires that these temporary filters be installed and the plant shut down upon being notified of an eminent ash fall event. No prefilter banks are required to be installed for the HPCS diesel generator.

The team found numerous discrepancies and inadequacies with the design, and examples of non-integration of the operational or maintenance requirements for the diesel generator systems with the design requirements. The following paragraphs describe the conditions found and the remedial actions taken or planned by the licensee:

(1) <u>No Analysis of Oil Bath Combustion Air Filters for Dust Storm</u>

The licensee had no analysis which documented the capability of the Division 1 and Division 2 oil bath combustion air filters to function for the design basis dust storm. An analysis was performed during the inspection which did show their capability, but it had not been verified or approved at the close of the inspection.

(2) <u>No Analysis of Temporary Filters for Ash Fall</u>

The licensee had no analysis which documented the adequacy of the temporary filters for the design basis ash fall event. An analysis was performed during the inspection which indicated the filters could be fully loaded at 19 minutes into the event if the systems were operated per the existing abnormal conditions procedure. For this event, with the plant shutdown, at least one diesel generator must be operational per the Technical Specifications. Since, per the licensee, the changeout time for the filters would be three hours, the Technical Specifications requirement cannot be met and the design and/or procedure is inadequate.

Additional analysis was performed which showed that if the abnormal conditions procedure were changed to require shut off of the ventilation air drawn through these filters, the time until changeout was required would be increased to approximately 6.5 hours. However, the potential adverse effects of this mode of operation, such as infiltration of ash into the rooms, had not been fully analyzed.

(3) No Analysis of Oil Bath Combustion Air Filters for Ash Fall

The licensee had no analysis which documented the ability of the Division 1 and Division 2 oil bath combustion air filters to function for the design basis ash fall event with the temporary prefilters in place. This analysis was performed during the inspection showing their adequacy, but it was not verified or approved at the close of the inspection.

(4) Inadequate Abnormal Operating Procedure

The Design Basis Ash Fallout Procedure, 4.12.4.5, requires that if the diesel generators are not required for operations (it is not clear what plant condition this refers to), the operator is to manually adjust two ventilation dampers in each diesel generator room "so that approximately 2000 CFM of outside air is drawn through the filter bank to insure pressurization of the room." However, no provisions are made for the operator to accomplish this task; the damper positions are not pre-marked and there is no instrumentation which would facilitate this action. As written, the filters will load up faster than they can be changed and ventilation air flow cannot be adjusted as required by procedure.

(5) No Documentation of Filter Structural Adequacy

The mountings for the temporary filters are permanently installed grid type frameworks. They are installed in the reverse direction from the normal position recommended by the manufacturer. That is, the flow induced dp tends to unseat rather than seat the filters, potentially allowing some blowby of the ash, and the 24 inch by 24 inch cardboard filter frames are supported at four points by the attachment clips rather than uniformly around the filter periphery. The licensee had no documentation that the filters are structurally adequate with this configuration to sustain the differential pressure they would experience at loaded conditions. The licensee contacted the vendor and received verbal assurance that the filters were structurally adequate and a commitment by the vendor to provide written documentation to that effect.

(6) No Testing of Temporary Filter Arrangement

The licensee had performed no testing of the diesel generator systems with the ash fall temporary filters installed or trial fittings of the filters. Such testing would have the potential

to reveal difficulties with installation, time required to perform installation, engine performance problems associated with higher inlet differential pressure, HVAC adjustments required for higher inlet differential pressure, etc.

(7) Other Ash Fall Filters

Abnormal Conditions Procedure 4.12.4.5, Design Basis Ash Fallout requires that temporary filters such as at the diesel generator air intakes be installed at 19 other locations in the plant. In further discussion with the licensee, it was learned that, as with the diesel generator filters, no analyses have been performed for the design basis ash fall event or the design basis dust storm for these other locations. Neither have there been any preoperational tests performed with the filters in place or any trial fitups. Considering that at these other locations, the filters serve purely ventilation functions, which at the diesel generator location produced unacceptable filter changeout times, it is expected that the same results may be found at these other locations.

The licensee was asked how many of the temporary filters of the size required by the diesel generator were maintained onsite. The reply was 666. Per the procedure, 404 are required for the initial loading of diesel generator locations plus all the other locations which require this size filter. Considering the time to changeout that was calculated for the diesel generator location and the 20-hour duration of the event, it is highly unlikely that when the changeouts required for the other locations are finally calculated, there are enough filters to last the duration of the event.

Another consideration which may require the licensee's attention is the manpower to effect the required changeouts. Considering what the probable changout rate will be for all of the filters and the time required to effect a changeout of any one of them, it would appear to be unreasonable to expect that they all could be changed out as fast as they would load up with the manpower resources that would likely be available. Additionally, with a design basis ash fallout event occurring, these resources could not be augmented by outside resources.

Overall, the licensee's entire program for handling the design basis ash fall event was found to be poor. The design does not appear to be well thought out. The operating procedure is unrealistic, untested by walkthroughs, and apparently unable to be performed in certain areas. No preoperational testing was performed on the system, and insufficient resources appears to be available onsite to carry out the design intent of the system. This is considered by the team to be a major example of lack of coordination between the various facets of the licensee's organization-Engineering, Operations, Maintenance, and Quality Assurance. Items (1) through (7) above remain

unresolved pending additional evaluation by the licensee and NRR (50-397/87-19-09).

(8) Overdue Maintenance on Permanent Filters

Cleaning of the permanently installed oil bath combustion air filters is currently controlled by the plant's Scheduled Maintenance System (SMS), a computerized scheduling and tracking system. The filters are currently on a 52-week cleaning cycle. At the time of the inspection, the filter for the Division 3 engines was past due for its required cleaning. When asked why the maintenance had been deferred, the licensee responded that a plant outage was required to perform this work. The team considers this to be questionable for two reasons: (1) the filters can apparently be cleaned when the plant is in operation by taking one diesel at a time out of service while the plant is in an LCO action statement, and (2) an outage has occurred since the maintenance was due.

In further investigation of this situation, the licensee was asked how it is determined, i.e., by what criteria, that scheduled maintenance on safety-related equipment is acceptable to be deferred. The licensee replied that the decision is made at the discretion of the maintenance supervisor. The licensee was asked how such deferred maintenance is tracked. The reply was, through the SMS system. The licensee was then asked, what ensures that maintenance is not deferred for an inordinate period of time. The reply was that it is deferred at the judgment of the maintenance planner/supervisor. It was acknowledged that there are no proceduralized safeguards to ensure that deferred maintenance on safety-related equipment receives adequate formal evaluation and control of rescheduling. The team feels that this is a weakness in the plant's maintenance program which has the potential to negatively affect plant safety. This is an open item (50-397/87-19-10).

(9) Nitrogen Tank Threat To Diesel Generators

During normal operation of the plant, the primary containment is inerted with gaseous nitrogen to prevent an explosion of hydrogen which may result from an LOCA. This nitrogen is supplied from an approximately 11,000 gallon liquid nitrogen storage tank located at the southeast corner of the diesel generator building. This is a nonsafety-related system and was not originally designed to withstand the effects of natural phenomenal such as earthquake or tornado. Were the tank to be ruptured due to being toppled over by an earthquake or tornado or due to being struck by a tornado generated missile, its contents could be spilled on the ground in close proximity to the diesel generator air intakes. Since liquid nitrogen must be kept at cryogenic temperatures to remain liquid, it would very quickly vaporize, potentially starving the diesel generator intakes of oxygen. It is also of some concern what

negative effects the sudden dramatic change in environmental temperature might have on the engines.

This event scenario could occur coincident with an LOCA or during normal operation when the diesel generators may automatically start in response to a loss of offsite power which would also be likely to occur as a result of an earthquake or tornado.

Although the licensee could produce no analyses to refute this accident scenario, analyses were initiated during the inspection. This is an open item (50-397/87-19-11).

(10) Diesel Generator Fuel Supply

Technical Specification 3.8.1.1.6.2 requires that the Division 1 and Division 2 diesel generators have minimum of 53,000 gallons of fuel in their respective main fuel oil storage tanks at all times the plant is in mode 1, 2 or 3. Per FSAR Section 9.5.4.3, the minimum storage capacity is sufficient for 7 days. This is consistent with the requirements of Regulatory Guide 1.137, which requires that fuel oil storage capacity be calculated based on assuming the diesel generator operates continuously for 7 days at its rated capacity or based on the time-dependent post LOCA load.

The capacity at WNP-2 was apparently based on 7 days operation at rated capability as per Burns and Roe calculation number 5.43.02. This calculation is based on the actual fuel consumption rates at rated load that were observed during the engines' fuel consumption tests. The number one engine rate was 5.10 gallons/minute, or 51,408 gallons for 7 days. The number two engine rate was 5.4039 gallons/minute or 54,437 gallons for 7 days. Therefore, the Technical Specification minimum storage requirement for the number 2 engine is not consistent with the regulatory guide or the FSAR statement.

This inconsistency is not a violation of requirements, per se, since (1) the licensee is not committed to Regulatory Guide 1.137 and (2) if the licensee were to calculate the fuel requirement based on time-dependent load profile, it would almost certainly be less than 53,000 gallons. However, it is an inconsistency which has the potential to confuse the operator or engineer using this information.

An additional factor which may generate operator confusion is the inconsistency in units of measure used in determining the actual amounts of fuel in the main storage tanks. The Technical Specifications require 53,000 gallons. Annunciator procedures 4.800.C1-9.1 and 4.800.C5-9.1 for the tank low level alarms indicate the set points at 81% (this is consistent with the local gage). The sounding devices at the tanks (a steel tape and a rod) are graduated in feet and inches. There are no correlations in the Technical Specifications or the annunciator

procedures between any of these. Additionally, the 81% value in the annunciator procedure is subject to misinterpretation, to wit, 81% of tank volume, 81% of tank level, or 81% of the instrument range. This observation would call into question the consistency of values with which the operator must deal which are contained in other operating procedures.

Subsequent to completion of the inspection, the licensee determined that misinterpretation of tank measurement parameters had resulted in errors in the licensee procedures for determining diesel generator tank fuel oil capacities. As a result, the licensee determined that the minimum fuel oil limits specified in plant Technical Specifications had not been maintained on several instances. The specific discrepancies are described in licensee LER 87-026. This is an apparent violation of Technical Specification requirements (50-397/87-19-12).

(11) Diesel Fuel Oil Loading

The inspector walked through the method used to fill the diesel fuel oil storage tanks with emphasis on methods of preventing inadvertent contamination (introduction of foreign material). The review included procedures PPM 7.4.8.1.1.2.3, "Diesel Generator Fuel Test," and PPM 12.5.21, "Diesel Fuel."

These procedures specified requirements for sampling the storage tank periodically and fuel shipments prior to transferring the contents to the storage tanks. The parameters to be analyzed and their specifications are listed in the procedure. The method of sampling is not specified in the procedure but standard practice is to use a sampling bomb which opens at the bottom of the tank. There is no procedure which specifies the method of connecting and transferring the diesel fuel shipment to the storage tanks and there is no Quality Assurance involvement.

The inspector also noted that the locks on the fuel oil fill connections are ineffective because the screwed fitting just below the lock can be disconnected with the pipe wrench stored at the station. This fitting is, according to the operators present, the connection used to connect the shipment to the fill line.

This is an open item (50-397/87-19-13).

g. Instrument Setpoint Calculations and Methodology

The team reviewed the setpoint calculation methodology used at WNP-2 for safety-related instruments. The methodology used to determine instrument loop inaccuracy is required by NRC Regulatory Guides 1.105 and 1.89, to take into account any inaccuracies resulting from normal plant operation as well as those inaccuracies resulting from LOCA, HELB, seismic, and radiation exposure effects. The General

Electric BWR setpoint methodology, as shown in specification 22A5261 and licensing topical report NEDC-31336, considered only normal plant conditions and did not take into account the effect of harsh environment conditions. Burns and Roe setpoint calculations also did not take into account harsh environment or seismic effects on instrument accuracy. WNP-2 environmental qualification evaluations did not apparently combine normal operation and accident environment effects.

Pressure switches LPCS-PS-1 and -9, used for the automatic depressurization system AC interlock permissive, were selected for detailed review. These switches have a Technical Specification inaccuracy limit of 8 percent of full scale. The normal operation inaccuracy calculated by General Electric was 4 percent of full scale, and the environmental effect inaccuracy calculated by WPPSS was estimated to be 3.44 percent of full scale. These results had not been combined, nor had seismic effects been evaluated. Algebraic summing of these results for these particular instruments appears to leave very little margin with respect to Technical Specification limits.

This item remains unresolved, pending additional evaluation by the licensee of the combined effects of normal operation with environmental and seismic considerations on setpoint methodology (50-397/87-19-14).

h. Design Verification Criteria in Procedure EI 2.15 Revision 4

ANSI N45.2.11 requires that safety-related calculations be design verified to assure design adequacy. In Revision 4 of WNP-2 procedure EI 2.15, the criteria used the phrase "significant affect" to determine whether design verification was required or not; however, no definition was provided for "significant" to provide guidance for implementation by the engineer. The team reviewed a number of WNP-2 safety-related and nonsafety-related calculations and found that each had been verified. During the inspection, WPPSS issued Revision 5 of this procedure which eliminated the phrase "significant affect" from the design verification criteria. This action was satisfactory to resolve this concern.

i. Incorrect Design Documents

Several examples were discovered where the actual physical configuration of plant structures, systems, or components were not in accordance with the most current design documents.

Examples:

(1) Drawings M852, Revision 12, shows a floor drain located in the HPCS Diesel Fuel Oil Day Tank Room. This drain does not exist in the plant.

(2) Drawing M512, Sheet 1, Revision 3, shows the piping inboard of the Fill Isolation Valve on Diesel Oil Storage Tank #2 as

Seismic Category II and the piping outboard as Seismic Category I. The reverse is actually the case.

(3) Drawing M512, Sheets 2 and 3, Revision 1, shows valves DO-RV-4A1 and DO-RV-4B1 respectively as relief valves. In fact, they are spring loaded check valves.

(4) Pressure switches DLO-PS-4A1, 4A2, 4B1 and 4B2 shown on drawings M512, Sheet 2, Revision 1, and M512, Sheet 3, Revision 1, respectively, are labeled as L.O. circulating pump low pressure alarms. They cannot perform this function since they are isolated from the circulating pump discharge by a check valve. Therefore, the labeling is incorrect. Additionally, these pressure switches have been deactivated, and this is not noted on the drawings.

(5) Check Valves DSA-V-37A1 and 37A2, shown on drawing M512, Sheet 2, Revision 1; and DSA-V-37B1 and 37B2 shown on drawing M512, Sheet 3, Revision 1, are shown backwards from the required direction of flow. The actual installations of the valves appear correct.

(6) Check valves DO-V-53A1 and DO-V-53A2 and associated lines, indicated on drawing M512, Sheet 2, Revision 2, are not installed.

(7) Several Restricting Orifices RO-3A-1, RO-4A-1, RO-3A-2, and RO-4A-2 and associated lines, indicated on drawing M512, Sheet 2, Revision 2, are not installed. Restricting Orifices RO-3B1, RO-4B-1, RO-3B-2, and RO-4B-2 and associated lines, indicated on drawing M512, Sheet 3, Revision 2, are not installed.

The above examples note a lack of design control and attention to detail in that the licensee has failed to correct or keep current diesel generator flow diagram M512. If the basic design documents for the plant do not accurately reflect the actual plant configuration, then they cannot be relied upon by operations and engineering personnel in the performance of their respective functions, or if they are relied upon, can foster errors in plant operations or subsequent engineering. This item remains unresolved, pending additional licensee evaluation of the failure of design documents to accurately reflect actual plant configuration. (50-397/87-19-15).

j. <u>Procedural Control Over Use of ADS Inhibit Switch</u>

For FSAR Chapter 15 design basis events, the operator has the capability to prevent the opening of the ADS valves by pressing a timer reset pushbutton in the control room at 90 to 105 second intervals. A two position inhibit switch was added to the control room panel by DCP-85-0073-0A for the purpose of preventing ADS operation for the anticipated transient without scram (ATWS) event. For this unlikely event where failure of the control rods to insert into the reactor core is postulated, the operator is required to

inhibit ADS actuation in order to prevent dilution of the sodium pentaborate solution injected into the reactor core by the standby liquid control system.

WNP-2 procedure 5.1.1, "RPV Level Control," was modified in mid-1985, but placed no constraints on the use of the two position ADS inhibit switch. The ADS inhibit switch, when activated, prevents ADS operation which may be required for small break LOCA events, and reduces the availability and reliability of the ADS safety function. The WNP-2 procedure should have designated use of the timer reset pushbutton for design basis events and constrained any use of the ADS inhibit switch to only the ATWS event.

Potential use of the ADS inhibit switch, in lieu of the timer pushbutton switch, is safety significant in that it reduces the availability and reliability of the ADS toward performing its ECCS safety function. This item remains unresolved, pending additional licensee evaluation of requirements for constraints on use of the ADS inhibit switch (50-397/87-19-16).

k. ADS Backup Nitrogen Supply Discrepancies

Several discrepancies were noted by the team with the safety-related backup nitrogen supply system for the automatic depressurization valves. This system is required to provide a 30-day supply of nitrogen to operate the ADS valves in the event of failure of the nonsafety-related normal nitrogen supply. It is also designed to provide the ability to replenish the backup supply from a remote location that is accessible post-LOCA.

(1) Bottle Capacity Not Per FSAR

FSAR, Section 9.3.1.2.2, states that the ADS backup nitrogen bottles have sufficient capacity to provide a 30-day supply using conservative leakage estimates and considering 48 cycles of the ADS valves.

WPPSS calculation 5.46.05, Revision 1, dated August 28, 1984, shows that with a 30-day supply in the bottles, only 18 ADS valve cycles can be performed.

The source of this error was determined to be a Technical Specification change that was made early in the plant life to reduce the minimum required backup bottle pressure from 2490 psig to 2200 psig. No attendant change was made in the FSAR.

The design basis for the original 48 cycle requirement could not be produced by the licensee. However, an argument was made that considering the worst case long-term function the ADS valves must perform, i.e., provide an alternate shutdown cooling section of flowpath, the 18 cycles would be adequate. This argument will be presented in support of the FSAR change the licensee intends to make.

It should also be noted that the number of cycles addressed in the FSAR is the number of individual ADS valve openings rather the number of times all of the valves can be cycled. The current FSAR wording is not clear on this point and can easily be misinterpreted. This item remains unresolved, pending additional licensee evaluation (50-397/87-19-17).

(2) Time Available for Bottle Changeout

The backup nitrogen system for the ADS valves has two divisions with each division having two sources of nitrogen. The primary source is a bank of bottles containing the 30-day supply and located in the reactor building. The secondary source is a station located in the diesel generator building hallway where one bottle for each division is located and other bottles can be connected. This station can be manually placed into service whenever the primary source is exhausted. Its location allows operation when the reactor building may be inaccessible post-LOCA.

Warning that the primary source pressure is approaching the critically low stage is provided by a low header pressure alarm. Burns and Roe calculation number 5.46.05, Revision 1, dated September 3, 1982, was generated to determine the time available from receipt of the alarm until the ADS valves would begin to close and therefore the time available to valve in the secondary bottles. It addressed the situations where the valves would require one cycle open for each valve after the alarm and where the valves would only require being held open. The results were 54 and 57 minutes for the A and B divisions respectively for the one cycle scenario and 3.72 hours and 3.97 hours for the held open scenario.

In generating this calculation, Burns and Roe used two apparently incorrect non-conservative design inputs. A Drywell temperature of 200°F was used whereas for the small break LOCA for which this system is required, the temperature given by FSAR is 340°F. The second error was the use of 75 psid as the minimum differential pressure required to operate the ADS valve operation piston. The vendor manual for the valves (Crosby manual VPF6115-18 (1) states the minimum required differential pressure as 88 psig. The effect of these errors would be to lower the actual response time available.

The current annunicator response procedure for the low pressure alarm have no indication to the operator of the time available to put the secondary supply in service after the alarm is received. Since this time may be very short, the team considers this to be a significant weakness in the procedures. This item remains unresolved, pending additional evaluation by the licensee (50-397/87-19-18).

(3) Bottle Installation Not Per Design Drawing

The design of the racks to seismically restrain the backup nitrogen bottles for the ADS valves is shown on WNP-2 drawing FSK-346, Revision 3, dated June 18, 1983. Note 6 on this drawing requires that shims be placed under the bottles as required depending on the individual bottle height to achieve a snug fit between the top of the bottle and the collar of the rack. These shims had not been installed for any of the bottles for either the primary or secondary stations in both divisions. As a result, all of the bottles were free to move around in the collars during a seismic event, potentially causing failure of the bottles and/or the rack.

At the conclusion of the inspection, the licensee had initiated a design change to the restraining system for the bottles because the licensee felt that the existing design was not "user friendly" for maintenance personnel who perform the bottle replacements.

In addition to their not being installed in accordance with the design drawing, the racks were also assembled in a very careless manner. Bottles were missing, nuts were missing, and when they were present, they were not even assembled hand tight in most cases.

The failure to install the backup nitrogen bottles in accordance with the design drawings is an apparent violation of 10 CFR 50 Appendix B, Criterion V (50-397/87-19-19).

3. Maintenance and Surveillance

The team reviewed maintenance and surveillance activities associated with the systems under review by the team. The results of this review are summarized below:

a. Battery Surveillance Testing

The licensee uses 24 VDC, 125 VDC and 250 VDC batteries to supply Division 1 and 2 vital D.C. electrical power. In addition the licensee uses a 125 VDC battery to supply division three vital D.C. electrical power. Technical Specification 4.8.2.1 lists weekly, quarterly, once per 18 months, and once per 60 months surveillance requirements. The weekly and quarterly surveillances require battery inspections. The 18 month test requires the verification that the battery capacity is adequate to supply a dummy load, based on the battery design criteria, while maintaining the battery terminal voltage greater than or equal to a specified minimum voltage. The 60 month test requires the verification that the battery capacity is at least 80% of the manufacturer's rating by subjecting the battery to a performance discharge test.

The team reviewed the licensee's surveillance procedures against the Technical Specification requirements and had the following findings:

- The team observed that the battery load profiles contained in the Division 1 and 2 125 Volt 18 month battery surveillance tests did not agree with the latest calculations (2.05.01) or the FSAR Load Tables. This discrepancy had already been identified by the licensee prior to this inspection and had been documented in Nonconformance Report (NCR-237-013 (1/7/87), however this discrepancy was not resolved prior to the latest outage battery testing, prompting the 60 month performance test to be substituted for the 18 month service test.

- The battery capacity is affected by electrolyte temperature. Capacity decreases with decreasing temperature and increases with increased temperature. Batteries are rated by the manufacturer at 77°F and will lose approximately 11% capacity at 60°F; the minimum temperature permitted for the WNP-2 batteries by the technical specifications. Likewise a battery would gain approximately 9% capacity at the WNP-2 maximum permitted temperature of 100°F. The team observed that the 18 month service test disregards any effect that electrolyte temperature during the test would have on the apparent capability of the battery to meet the technical specification requirement to demonstrate the battery's ability to maintain the emergency loads operable. With no regard to the electrolyte temperature existing at the start of the test, no judgement can be made from the results of the service test to state whether or not the battery is satisfactory for its design requirements which includes operating the emergency loads at the minimum permissible cell temperature.

- The chart recorder used in the test device for the 18 and 60 month surveillances was scaled such that voltage changes could not be accurately determined.

As a result of the battery surveillance test deficiencies listed above, the 18 month service tests performed in 1986 failed to demonstrate the capability of the batteries to meet design requirements. This item remains unresolved, pending additional licensee evaluation (50-397/87-19-20).

The team observed that a temperature monitor exists for the safety related battery rooms. The team determined that the operating temperature range for the Class 1E battery rooms was 65 to 100 degrees F. Burns and Roe calculation 5.52.084 sheet 58 calculated only a high temperature alarm setpoint at 100 degrees F. No low temperature limit was established even though the batteries may begin to lose a significant portion of its capacity at approximately 60 degrees F. WPPSS subsequently revised procedure PPM 7.0.0 on September 2nd to add local temperature criteria of greater than 65 and less than 104 degrees F for shift monitoring of each of the three battery rooms, and provided an action statement to restore the room temperature within these limits by immediate corrective action. These added procedural controls satisfy this concern.

b. <u>Thermal Overload Testing</u>

Technical Specification 4.8.4.3 requires that thermal overload protection devices for valves listed in Table 3.8.4.3-1 be demonstrated operable at least once per 18 months by the performance of a channel calibration of at least 25% of all thermal overloads for the required valves. The licensee has used oversized thermal overloads so that during accident conditions the thermal overload protection will not prevent safety-related valves from performing their function. This is consistent with Regulatory Guide 1.106; "Thermal Overload Protection for Electric Motors on Motor Operated Valves," Revision 1, March 1977. Procedures 7.4.8.4.3.1 through .4 establish testing for the four groups of valves.

The team reviewed these procedures and test results from three groups of valves and made the following findings:

- For Group Four thermal overloads, tested in 1985, the test current prescribed by the procedure did not match the time to trip criteria specified by the manufacturer.

- For Group Four thermal overloads, maintenance personnel recognized that five thermal overloads installed did not match the size listed in the procedure. In all cases, maintenance adjusted the test current without appropriate review. In two cases the test current did not match the time to trip criteria.

- For Group Two thermal overloads, tested in May, 1987, revisions made to the procedure in accordance with the deviation procedure, 1.2.3, changed five thermal overload heater sizes, but did not change corresponding test currents used in the surveillance procedure.

- For Group Two and Three thermal overloads, in four cases the test currents prescribed by the procedure did not match the time to trip criteria specified by the manufacturer.

Thermal overload relay trip time is current dependent. To test thermal overloads the procedure should establish a current and a corresponding minimum time to trip criteria. Group 4 thermal overloads, tested in 1985, were the first overloads tested by the licensee. Due to calculational errors, most group 4 valves were tested at approximately 275% of the full-load motor current specified by the vendor. This corresponds to a time to minimum trip of approximately 50 seconds. The licensee's procedures specify 40 seconds which corresponds to 300% of full-load motor current. A review of the data taken during the 1985 testing shows that none of the overloads tested at 275% tripped quicker than 50 seconds, indicating they performed as designed, however this is an example of an inadequate procedure.

A review of the group four test results shows that in five cases maintenance personnel identified heaters of sizes different from that specified in the procedure. In all five cases the maintenance personnel tested the overloads at a current other than that specified in the procedure. The test current used and the as found

heater sizes were noted by those performing the test in the comments section of the procedure. In two cases, for valves RCC-V-6 and RHR-V-3A, the current used did not correspond to the minimum trip time criteria specified in the procedure. In these two cases, test data shows that the thermal overloads performed as designed. However, changing thermal overload test currents is an example of maintenance personnel making a procedure revision without the appropriate review.

In March 1986, revision 1 to the thermal overload procedures for all groups was issued. The team reviewed the group four procedure revision and noted that the five overloads mentioned in the previous paragraph were not revised to reflect the hardware installed. In addition, the testing current was changed from 275% of full load motor current to 375% of the nominal trip current. However, the time to trip criteria remained at 40 seconds. The appropriate minimum time to trip for the revised test current was 22 seconds. This revised procedure was never used.

Prior to the testing of group two and three thermal overloads, the minimum time to trip criteria was recognized to be in error and revised to 22 seconds. In addition, for both groups, thermal overload sizes in the procedures were compared to the sizes in licensee drawings and revised accordingly. For five group two thermal overloads the corresponding test currents were not revised.

Of the five thermal overloads, there are two outlying examples. In the first, valve RRC-V-16A was originally listed in procedure 7.4.8.4.3.2 as having G30T45 thermal overloads, requiring a test current of 60 amps. The revision to the procedure changed the thermal overloads to size G30T11. Although the test current was not changed, the correct current for G30T11 overloads corresponding to a minimum time to trip of 22 seconds is 1.9 amps. Test results indicate that the three thermal overloads tripped between 35.3 and 42.4 seconds. Had 60 amps been applied across a G30T11 heater for 35.3 seconds it would have burned out. The inspector observed that G30T11 heaters were installed for valve RRC-V-16A and that there was no evidence that the heaters had burned out.

In the second example, valve SW-V-24 was originally listed as having G30T21 heaters, requiring a test current of 5.4 amps. The procedure revision changed the heaters to size G30T26 which require 8.7 amps to have a minimum trip time of 22 seconds. Again, the trip current was not changed. According to the vendor drawings, at 5.4 amps one would expect a minimum time to trip of approximately 80 seconds. Test results indicate that the three thermal overloads tripped between 40.6 and 50.0 seconds. The inspector observed that G30T26 heaters were installed for valve SW-V-24A. This indicates that if the three overloads had been tested in accordance with the procedure, all three tripped faster than design. On August 28, 1987, the licensee tested the thermal overloads for SW-V-24A and found them to operate appropriately.

In addition to the previously mentioned procedural inaccuracies, the inspector found four examples of group two and three overloads test currents inappropriate for the heater size were specified by the procedure. All four examples were in the conservative direction so there was no question of thermal overload operability.

Finally, although deviations existed for group two and three testing, at the time of the inspection no deviations had been issued for group one and group four. In addition no document was presented tracking the future revision to group one and four based on the errors found in group two and three procedures. Had changes been made in accordance with the methods used to revise the group three procedure, the errors in the testing of group two overloads wouldn't have happened.

The inadequacy of procedures 7.4.8.4.3.2, 3, and 4 is an apparent violation of Technical Specification 6.8.1 (50-397/87-19-21).

Failure to properly implement changes to procedures 7.4.8.4.3.2 and .4 is an apparent violation of Technical Specification 6.8.3 (50-397/87-19-22).

c. Loss of Offsite Power Testing

The inspector reviewed the licensee's surveillance procedures corresponding to the Technical Specification requirements to verify the transfer between the offsite transmission network and the onsite Class 1E distribution system. Specifically, the inspector reviewed procedure 7.4.8.1.1, "18 month manual and auto transfer test, startup to backup station power," corresponding to Technical Specification 4.8.1.1.1.b, procedure 7.4.8.1.1.2.5, "Standby Diesel Generator Loss of Power Test (Divisions 1 and 2)," corresponding to portions of Technical Specification 4.8.1.1.2.e, and procedure 7.4.8.1.1.2.7, "Standby Diesel Generator LOCA Test (Divisions 1 and 2)" corresponding to portions of Technical Specification 4.8.1.1.2.e. The following findings were made:

- Procedure 7.4.8.1.1.2.5 did not specify which breakers open on vital bus undervoltage.

- Procedure 7.4.8.1.1.1.2 did not require the functional testing of the backup transformer.

Division One and Two bus primary undervoltages initiate a two second time delay relay. The time delay relay initiates, among other things, load shedding. Seven breakers on three separate buses are opened on load shedding. Procedure 7.4.8.1.1.2.5 states, "verify that...loads are shed from the bus." Technical Specification 4.8.1.1.2.e.4.a)1) requires that verification be made of load shedding from the buses. Although the procedure quotes the technical specification, the lack of a verification of specific breakers opening is a weakness since upon load shedding not all breakers off the main 4 KV vital buses open nor are all breakers that open off the main 4 KV buses (SM-7 and SM-8). The

inspector discussed this weakness with the engineer responsible for the procedure who committed to address it prior to performing the test during the next outage.

The second weakness identified was the lack of a full functional test of the backup offsite power source for the 4 KV vital buses. At the time of inspection it was apparent that the backup offsite power source, and specifically the backup power transformer TR-B, was only being functionally tested to a fraction of its design load requirements. TR-B supplies both main 4KV vital buses SM-7 and SM-8. Procedure 7.4.8.1.1.1.2 Revision 3, tests the transfer from startup power to TR-B. Prior to the test, all rotating equipment with redundant equipment available on the bus not tested are shut down and the redundant equipment started. During the test, TR-B is only loaded with the non-shed loads of one bus excluding those mentioned above. The licensee should evaluate the need for increased functional testing of TR-B.

This is an open item (50-397/87-19-23).

d. Functional Test and Calibration of Time Delay Relays

Time delay relays are used in a number of safety-related control circuits. These safety-related Class 1E components are not usually explicitly identified in Technical Specifications; nevertheless, they are required to have design basis setpoint calculation values and to be periodically tested and calibrated in accordance with the WNP-2 Chapter 7 FSAR commitments to IEEE Std. 279-1971 and IEEE Std. 338-1975. The team requested both setpoint calculations and periodic test surveillance instructions for various time delay relays in safety-related systems, but was informed that no such documentation existed. For the majority of such time delay relays, there was no indication that any periodic surveillance testing had been performed since the initial plant preoperational tests had been completed.

During the inspection, the licensee provided an April 19, 1985, inter-office memorandum that identified 22 time delay relays in the 4KV switchgear requiring calibration. There was no indication that any other safety-related time delay relays were subsequently identified as being subject to periodic test and calibration. Seven specific time delay relays were selected by the team to illustrate this concern. In each instance, the WNP-2 master equipment list correctly designated these particular time delay relays as Class 1E devices, but this information did not lead to the development of appropriate documentation. These examples are:

(a) SE-RLY-V/2A3 and 2A4, that provide 12 second and 62 second time delay values to control the slow opening of the service water pump discharge valve to minimize water hammer effects.

(b) SGT-RLY-TK/2A1 and 2A2, that provide a 30 second time delay for automatic start of the redundant standby gas treatment system.

(c) RHR-RLY-K54A, that provides a 10 second time delay for minimum flow bypass for the RHR pump.

(d) RHR-RLY-K70A, that provides a 5 second time delay for starting of the RHR pump.

(e) RHR-RLY-K93A, that provides a 10 minute time delay before the operator can manipulate RHR heat exchanger valves after the start of an accident.

Failure to provide instructions for the periodic calibration and testing of time delay relays is considered an apparent violation (50-397/87-19-24).

e. Service Water System

The Service Water System (SWS) provides cooling water to several safety-grade components such as the HPCS Diesel Engine, 1A Diesel Engine, and RHR heat exchanger.

The team reviewed maintenance activities on the SWS. During the team inspection walkdown of the SWS, an overhead crane in service water pumphouse 1A was observed to have its block extended such that it could impact safety-related conduit during a seismic event. The license has no procedure covering seismic control of lifting equipment installed in safety-related areas. This is a repeat example of a similar concern raised in a previous inspection report (86-33-01), and remains an open item (50-397/87-19-25).

f. Emergency Diesel Generators (EDG)

The emergency diesel generators (EDGs) provide emergency AC power in case of loss of offsite AC power. The team reviewed the maintenance activities associated with the EDGs and the High Pressure Core Spray (HPCS) diesel generator. No deficiencies were noted.

g. Missing Hardware on Safety Related Valve

During a walkdown inspection of the Service Water System, the hardware for butterfly valve SW-V-165B was found to be broken off. This valve is required to be operated to the open position to bypass the spray ring and send the service water directly to the spray pond whenever pond temperature is less than 60°F or before outside ambient temperature can fall below 32°F. Without the hardware in place, the operator cannot operate the valve without using a wrench or other improper tool. Furthermore, the operability of the valve is questionable considering the possible cause of the failure of the handwheel. The licensee has initiated action to repair the valve.

h. Standby Service Water System Pool Temperature Elements

The team reviewed the Standby Service Water System pool temperature elements installation to determine the adequacy of monitoring the Technical Specification Limits on pool temperature.

The review showed that the pool is generally about 14.5 feet deep (overflow point to pool bottom), the bottom end of the two foot long temperature probe is one foot above the general pool bottom and is located under the Standby Service Water building where the pool depth is 26.5 feet. Since the temperature probe is located in the service water flow path to the pump, the temperature of the water being supplied to the plant (system in service) is monitored accurately. The WNP-2 Technical Specifications require the water temperature to be less than 77°F. Since the system is normally secured, the pool water is stagnant and there will be a temperature gradient with the warmest water at the top of the water in the general pool area and the coolest water under the Service Water building in the deepest part. Since the Surveillance Procedure verifies that the temperature at the temperature probe is less than 77°F, and this temperature may not be representative of the overall pond temperature, this is an apparent violation of WNP-2 Technical Specification Surveillance Requirement 4.7.1.3 which requires verification every 24 hours that the ultimate heat sink water temperature is within its limit. This item remains unresolved, pending additional licensee evaluation (50-397/87-19-26).

During the above review, the inspector reviewed Design Change Package (DCP) 86-0155-0A dated April 23, 1986. The DCP modified the support for the temperature element to facilitate maintenance. On page 4 of the DCP, Note 1 of the "Notes on Installation" indicates that the original design showed perforations in the pipe containing the temperature element, but because of the slow temperature response of the pool, these perforations are no longer needed. There are no calculations or analysis concerning time response which support the determination that the perforations are not necessary. Further review of the DCP drawings shows that the perforations were not changed and the licensee does not believe that the pipe containing the perforations was removed. This item remains open pending additional licensee action to provide a basis for the note (50-397/87-19-27).

i. <u>Automatic Depressurization System (ADS)</u>

During the ADS system walkdown, the inspection team noted that seismic restraints were improperly restored on the backup nitrogen cylinders for ADS following nitrogen cylinder replacement. The licensee has no procedure addressing the requirements for proper cylinder replacement. The nitrogen cylinders mounting brackets were not tight around the collars of the nitrogen cylinders, nor were the bolts and nuts secured properly. It was determined from the licensee that they use training as the method for teaching their operators the proper replacement of the nitrogen cylinders. The team considered that a procedure should have been issued for nitrogen cylinder replacement to ensure proper collar engagement around the nitrogen cylinders. In addition, the team noted that temporary scaffolding was noted as being installed in the vicinity of the backup nitrogen supply for ADS since June 1987. This scaffolding was constructed in accordance with maintenance procedure 10.2.53 which provides guidelines and seismic requirements for scaffolding

ladders, tool gauge boxes and metal storage cabinets. The team felt that the scaffolding was constructed correctly and was tagged in accordance with procedure 10.2.53 as required. Thus, scaffolding should have been removed upon completion of its intended function.

j. Multiple Features of CIA Valves

Containment Instrument Air (CIA) solenoid valves CIA-V-39A and 39B serve as the safety-related isolation valves between the safety-related and nonsafety-related portions of the system. Their function is to close upon loss of the nonsafety-related N_2 bottles.

In July 1986, CIA-V-39A was found to be inoperable during the performance of surveillance procedure T.S.S.7.4.5.1.21. NCR 286-0333 was generated as a result. It was dispositioned "use-as-is" with the reason being given that check valve CIA-V-41A, which is in series with CIA-V-39A, serves as an isolation valve and provides sufficient isolation for the system. This NCR also took credit for the normal N_2 inerting supply and the CIA compressors.

The team did not concur with this disposition for the following reasons:

(1) Per values given in the FSAR (Section 9.3.1.2.2), the maximum allowable leakage rate for all components of one branch of the backup N_2 supply is approximately 4 SCFH. Therefore, the maximum allowable leakage rate of the check value CIA-V-41A must be less than or equal to 4 SCFH. Existing plant IST procedures do not verify the ability of these valves to meet this requirement. Therefore, a nondetectable failure can exist. IEEE Standard 379-1977 on single failure states "...identified nondetectable failures shall be assumed to have occurred."

(2) Since the normal N_2 supply and the CIA compressors are associated with the nonsafety-related portion of the system, credit should not be taken for these.

Subsequent to the immediate disposition, the valve was cycled manually until it would operate electrically. However, after sitting idle for several minutes, it was again found to be inoperable electrically. The valve was then disassembled and internal contamination was found. It was then cleaned and reassembled. The source of the internal contamination was not addressed and no action was taken to preclude repetition.

In June 1987, while performing the same surveillance test, both valve CIA-V-39A and the same valve in the opposite division, CIA-V-39B, were found inoperable. NCR 287-219 was written. In violation of Plant Problems Procedure 1.3.12, Section 1.2.12.5, the originator did not indicate that the NCR was safety-related.

Section 1.3.12.5.E.3 of the same procedure requires the Plant Technical manager to check "yes" or "no" in the safety Significant Block. This block was incorrectly checked "no" in violation of the definition in Section 1.3.12.2.C.

In spite of at least one similar earlier failure of one of these valves and the simultaneous failure of both valves (one in each division) in an apparent common mode at this time, the licensee performed an inadequate root cause analysis and no appropriate corrective action as required by the licensee's procedure, Section 1.3.12.5.D.4 C and D. The valves were dissembled, cleaned, reassembled and tested.

One of the immediate disposition actions called out on the June 1987 NCR was to "exercise the valve manually (through bottom hole vent) until valve operates electrically." This is an improper disposition since it had been proven ineffective in the earlier NCR, and it involved no action which could have defined the cause of the problem or correct it. It could, at best, only mask the problem. Had the valve been operated successfully with manual assistance, there is every reason to believe it would have been put back into service with no form of corrective action having been taken.

In July 1987, during a plant shutdown, the valves were tested again, and again they both failed. At this point, the corrective action was determined to be adding a washer under the valve operating spring to increase the closing force on the valve. No NCR was written. This is a violation of the licensee's procedure, Section 1.3.12.5.A.1. Also, there is no evidence that root cause analysis was performed on this event as required or had ever subsequently been performed. The above described incidents have significance with respect to plant safety in that the operational and leak tight integrity of the solenoid valves in question and their backup check valves is vital to ensuring that the design basis 30-day N_2 supply to the ADS valves is indeed sufficient for 30 days. The maximum allowable leakage rate to maintain 30 day's supply is extremely low, on the same order as containment isolation valves. By the licensee's failure to define the root cause of the recurring failures and then the taking of appropriate corrective action to preclude recurrence, it is reasonable to expect that failure could occur again. Since the leakage rate of the check valves has never been quantified, they can be assumed to leak more than the allowable. Therefore, it is reasonable to conclude that with failure of one of the solenoid valves in an LOCA situation with loss of the nonsafety-related containment instrument air supply, the backup air supply would not be sufficient for 30 days.

Considering this, the common mode failures that occurred on both divisions on two separate occasions, constituted the plant being "on a condition that was outside the design basis of the plant..." as described in 10 CFR 50.73.

The failure to identify, on multiple occasions, nonconforming conditions or, when they were identified, the failure to evaluate,

analyze or disposition these conditions in accordance with the NCR procedure is considered an apparent violation of 10 CFR 50 Appendix B, Criterion V (50-397/87-19-28).

k. Instrument Rack Terminations

Paragraph 8.3.1.3.1, Class IE Raceways, Cables, Equipment (Panels and Racks), of the FSAR identifies Instrument Racks (IR) 67, 68, and 69 as Class IE. DWG E538 W.O. 2808, Sheets 20 and 21, note 2, identifies IR-67, IR-68, and IR-69 as work being of Quality Class 1. Paragraph 3.2.4 (a), Quality Assurance Classification, of the FSAR reads "...All Quality Class 1 items meet the applicable provisions of 10 CFR 50 Appendix B." Paragraph 17.1.1.2 (c), Design Control QAR-3, of the FSAR establishes a system of independent reviews to assure applicable quality, regulatory code, and design basis requirements are properly translated into design and procurement documents for each structure, system and component. The documented review provides a check for design adequacy, inspectability, and compatibility with intended usage. WNP-2 termination and splicing Instruction No. 10.25.46 provides the direction and installation details required for all permanent electrical terminations.

During the inspection, the team conducted an evaluation of the installation and design requirements for low voltage (600 or below) terminations and heat shrinking specifications of plant instrumentation wiring. The results of the team's evaluation is as follows:

During plant tours, an inspector walked down portions of the ADS Nitrogen Supply System where IR-67, IR-68, and IR-69 were opened for observation of wiring installation. The inspector noted the following deficiencies:

- Crimping

  IR-68 wire terminal 87 insulation was excessively stripped and subsequently inserted and crimped to the terminal lug exposing its conductor at the end of the connector barrel insulator. Two wires were additionally found in IR-67 and another wire in IR-69 was found revealing the same conditions as stated above.

- Terminal Lugs

  Terminal wires 6,7 and 36,37 were spliced from terminal wires 5 and 35, respectively. Terminal wires 5 and 35 are size 16 with a larger insulator covering whereas terminal wires 6,7 and 36,37 are size 16 with a much smaller insulator. The inspector noted that the wire insulation is not commensurable with the size of the terminal connectors jacket. Therefore, terminal wires 6,7 and 36,37 connector appear to be unacceptably modified in IR-69.

Cabinet H-13, P631, ADS Division 2 in the control room was also inspected for terminations. Terminal wires B22-F8B, 10B, 14B, 16B, 25B, 29B, 33B, 35B, and 37B each had an additional wire whose lugs were terminated under one terminal screw which were not installed back to back.

- Heat Shrinking

  Terminal wires 36 and 37 were spliced to terminal wire 35 in IR-69. The heat shrinking tubing was improperly installed over the splice and subsequently exposing terminal wire 37 conductor from the splice connection.

Failure to comply with station procedure requirements for proper installation of electrical terminations is an apparent violation of 10 CFR 50, Appendix B, Criterion V (50-397/87-19-29).

1. Seismic Considerations and Housekeeping

During the first week of onsite inspection, an unsecured tool box and breaker truck were observed in the safety related SM7 switchgear room. These are heavy and relatively easily moved items which could damage important safety equipment during a seismic event. It appeared to the team that these items should be stored elsewhere or properly secured. During the second week of onsite inspection, the team noted that the breaker truck and tool box had been removed; however, the team again noted that ladders were left stored in both the SM7 and SM8 switchgear rooms and several sets of disassembled metal brackets and mounting hardware were piled in the corner of the SM7 switchgear room. Licensee procedure 10.2.53, "Seismic Control for Scaffolding, Ladders, Tool Gang Boxes and Metal Storage Cabinets," provides specific requirements for ensuring proper seismic restraint of equipment in safety related areas.

The team noted that the licensee was not providing adequate attention to plant housekeeping. The following deficiencies were observed:

(1) Piles of disposable absorbant towels and several cardboard boxes were observed in the DG rooms. This debris would contribute to drain plugging in the event of fire system actuation.

(2) A pile of drawings and papers, a discarded candy wrapper and several pieces of loose wire were observed on top of breaker cubicles in the SM8 switchgear room.

(3) Numerous cigarette butts and a cigarette wrapper were observed within the no smoking area adjacent to the diesel generator fuel oil tank fill manifold.

Licensee procedure 1.3.19, "Housekeeping", provides specific requirements for proper cleanup of work areas following maintenance activities.

The above is considered a violation of 10 CFR 50, Appendix B, Criterion V (50-397/87-19-30).

m. Improperly Controlled Plant Modification

The team noted that the licensee had installed temporary foam insulation filters on the ventilation louvers for the 4KV breakers on safety related SM7 switchgear. These filters were not installed using a maintenance order, as required by station procedures, nor was the modification properly reviewed as required by 10 CFR 50.59.

This is considered a violation (50-397/87-19-31).

4. Control Room Observations

The team observed operator activities in the control room. The operators appeared to be knowledgeable concerning their duties and responsibilities. The control room was free from unnecessary distracting activities. The background noise from the control room ventilation system is fairly high, but did not appear to interfere with operator response to audible alarms or communications. The operators were alert to unusual noise patterns such as a malfunctioning chiller and expeditiously corrected the problem.

The Main Control Panel appeared to be well marked with little impromptu marking to clarify labels. Equipment controllers provide clear feedback to the operators as to valve or controller position.

a. ADS System

The team walked down the control room indications for the Automatic Depressurization System (ADS). The operators were familiar with the indications, the indications were adequately marked, and all indications showed proper equipment lineup and operation. The team discussed the operation of the ADS inhibit switch with an operator. The operator was familiar with the switch and indicated he had received training on the operation of the switch as a result of the modification which installed the switch and also as a result of requalification training. The operator was able to describe how the switch was used and what indications occur when the switch is in the inhibit position. Verification of these indications is performed by the "Minimum Startup Checklist" which is performed prior to every startup. The operation of the switch is prescribed by the licensee's Emergency Operating Procedures which are symptomatic. These procedures include the symptoms for an ATWS. The team walked down the control room indications for the Electrical Power Distribution System including offsite power sources, the vital 4 KV busses, the vital 480 V busses, the 125 V and 250 V batteries, and the Emergency Diesel Generators. The operators were familiar with the indications, the indications were adequately marked, and all indications except a ground alarm showed proper equipment lineup and operation. The ground alarm was the result of a problem with the alarm circuit and not an actual ground. Alternate indication of the ground status on the affected buss was available, however, there is

no requirement or directive in place to monitor the alternate indication in the absence of the alarm function. Further review showed that there is no system in place to provide compensatory actions for an inoperable annunciator or alarm function. This is an open item (50-397/87-19-32).

b. Service Water System

The position indicator lights for SW-PCV-38A and 38B were not working. These valves are pressure control valves for the Standby Service Water System. Further review showed that a recent modification (DCP-86-0324) deactivated these valves and therefore deenergized the valve position indication. A field change (FCR-08) to this DCP modified the labels to the valves to identify them as having been deactivated. A Maintenance Work Request (MWR-AT-0444) to change the labels was initiated but not yet completed. The installation completed section of the Plant Modification Record was signed off on May 28, 1987, without MWR-AT-0444 being completed. This is another example, identified by the team, of the type of violation described in section 2.d of this report. The Reactor Feed Pump Turbine vibration recorders have handwritten notes dated December 1985 indicating that their labels are incorrect. This appears to be an excessive period of time to correct his deficiency. This is an open item (50-397/87-19-33).

The CRT displays for the Safety Parameter Display System (SPDS) are impossible to read from the Reactor Operator's desk and are difficult to read when standing at the Main Control Panel itself. This situation does not appear to be consistent with the FSAR description which says in Section 7.5.1.23 the CRT supplies additional information via high performance human factored displays useful for emergency response. This item is unresolved pending NRC review to determine if the SPDS meets licensee's commitments (50-397/87-19-34).

5. Quality Assurance/Training

The QA/QC activity have identified similar design control deficiencies to those found by the inspection team in some areas. This is evidenced by the inspector's review of QA/QC audit, surveillance, observation and inspection reports. In other areas of concern to the inspection team, the QA/QC activity has been limited or nonexistent.

In response to Region V inspection report No. 86-11 findings regarding the adequacy of QA/QC involvement, the licensee has strengthened the overall site quality verification organization and programmatic approach to assuring quality of facility operations. This revised approach is still in the implementation process. According to the licensee, details of this approach as discussed in the recent Region V SALP report are described accurately. Elements of the program, such as onsite QA/QC, Nuclear Safety Assurance Group and Corporate QA functions are expected to be fully implemented during FY 1988. During the implementation process, the licensee indicated that further adjustment and fine tuning of the approach will occur. Therefore, it may be premature to attempt an

assessment of the effectiveness of the licensee revised quality verification program at this time. However, to the extent that the licensee's quality verification program should have impacted the inspection team's findings, the following is evident:

a. No evidence of quality verification activity was produced by the licensee for the following inspection team findings.

(1) Battery design calculation for DC motor in-rush current.

(2) 125 VDC and 250 VDC design calculation correction factors for aging, temperature and specific gravity.

(3) Instrument tolerance consideration for harsh environments.

(4) ADS instrument rack electrical terminations.

(5) Reactor shutdown margin response time.

b. Limited evidence of quality verification activity was produced by the licensee for the following inspection team findings:

(1) Materials (scaffolding, loose parts, crane hook, etc.) stored in the vicinity of safety-related equipment creating a potential SSE concern.

(2) Inadequate surveillance procedure for MOV electrical overload.

(3) Inadequate surveillance procedure for periodic testing of safety-related batteries.

(4) Monitoring of safety-related battery room temperature design limitations.

(5) Improper closure of completed DCPs and NCRs (i.e., proper design not implemented and failure to provide root cause evaluations for repeated NCRs).

(6) Inadequate drainage capability for D.G. Rooms.

Licensee quality verification activities have identified in several surveillance, audit and observation reports design control problems associated with and similar to repeated failures of D. G. day tank valves and repeated failure of automatic valves for isolation of nonsafety-related air to ADS control system. In these cases, it appears that the plant staff did not perform root cause evaluations and did not take timely corrective action to the identified deficiencies. At present, site QA reports that there are 16 NCRs outstanding that are over 6 months old. While some of this work may be done, the documentation is not complete.

c. Evidence of quality verification activity was produced by the licensee for the following inspection team findings:

(1) Design calcs (Instrument setpoints).

(2) Weekly and 60-month battery surveillance testing.

(3) Automatic sprinkler system installation and diesel generator room flooding - removal of oil spills.

(4) Seismic restraints.

(5) Time Delay Relay (TDR) Setting (not specific to IEEE requirements).

(6) Thermal overload of MOV (Torque and limit switch settings).

d. Continuing weaknesses in the licensee's quality verification program appear to exist as follows:

(1) The focus of audits, surveillances, inspections and observations should be increased in the area of physical plant conditions and work performance.

(2) NCR, DCP, MWR, PMR or PDR completed reviews should include physical verification of design implementation by plant QA/QC.

(3) No NCR was issued for the nonconforming safety-related hand wheel for manual valve No. S.W. V-165B because licensee policy appears to allow individual interpretation/discretion in such cases. Furthermore, root cause evaluations may not be required unless a 50.59 review is required. 50.59 reviews are only required on NCRs if it is determined equipment is to be used "as is or repaired."

(4) Proper coordination of resources and personnel expertise (i.e., onsite QA/QC, corporate P.A. outside consultants, engineering, operations, NSAG, etc.) to further enhance program implementation appears to be in the developmental stage.

(5) Plant, corporate/QA interface appear to have improved to the extent that a working relationship exist that produces an environment for effective quality verification program implementation. However, this environment is in its infancy and may not have been disseminated down through the ranks of plant and corporate personnel.

(6) The training groups did not appear to be incorporating quality verification results into plant training programs (i.e., instructions to operations and test staff regarding reported seismic concerns and operations response to QASR 86-202 regarding operator requalification training).

6. <u>Unresolved Items</u>

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or

deviations. The licensee is requested to provide additional information on these items, as noted in the forwarding letter to this report.

7. Exit Interview

On August 28, 1987, an exit interview was conducted with the licensee representatives identified in paragraph 1. The inspectors reviewed the scope of the inspection and findings as described in the Summary of Significant Inspection Findings section of this report.