UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-369/85-06 and 50-370/85-06

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-369 and 50-370 License Nos.: NPF-9 and NPF-17

Facility Name: McGuire 1 and 2

Inspection Conducted: January 20 - March 20, 1985

Inspectors: C. W. Burger, for 6/20/85
W. Orders Date Signed

C. W. Burger, for 6/20/85
R. Pierson Date Signed

C. W. Burger, for 6/20/85
P. Skinner (March 4-8 and 11-15, 1985) Date Signed

Approved by: Virgil L. Brownlee 6/21/85
H. Dance, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 470 inspector-hours on site in the areas of operations, safety verification, surveillance testing, maintenance activities and refueling activities.

Results: Of the four areas inspected, four items of noncompliance were found in three areas (Violation of 10 CFR 50, Appendix B, Criterion III for inadequate separation criteria; Violation of Technical Specification (TS) 6.8.1 for failure to follow procedures; Violation of TS 4.8.1.1.2a for inadequate diesel generator surveillance interval and Violation of 10 CFR, Appendix B, Criterion XVI for failure to take prompt corrective action).

REPORT DETAILS

1. Licensee Employees Contacted

T. McConnell, Station Manager
*D. Rains, Superintendent of Maintenance
*G. Cage, Superintendent of Operations
*L. Weaver, Superintendent of Station Services
N. McCraw, Licensing Engineer
*J. Foster, Station Health Physicist
*M. Birch, System/Radwaste Engineer General Office
*R. Michaels, Station Chemist
*B. Hasty, McGuire Nuclear Station - QA
*P. Roberson, Associate Engineer - Performance

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on March 29, 1985, with those persons indicated in paragraph 1 above. The licensee acknowledged understanding of the violations and issues discussed and offered no substantive related discussion. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Licensee Action on Previous Enforcement Matters

This subject was not addressed in the inspection.

4. Unresolved Items*

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve noncompliance or deviations. New unresolved items identified during this inspection are discussed in paragraph 17.

5. Plant Operations

The inspection staff reviewed plant operations during the report period, January 20 - March 20, 1985, to verify conformance with applicable

*An Unresolved Item is a matter about which more information is required to determine whether it is acceptable or may involve a violation or deviation.

regulatory requirements. Control room logs, shift supervisors logs, shift turnover records and equipment removal and restoration records were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel.

Activities within the control rooms were monitored during shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in applicable station administrative directives. The complement of licensed personnel on each shift met or exceeded the minimum required by TSs.

Plant tours were taken during the reporting period on a systematic basis. The areas toured include but are not limited to the following:

Turbine Buildings
Auxiliary Buildings
Unit 1 and 2, Electrical Equipment Rooms
Units 1 and 2, Cable Spreading Rooms
Station yard Zone within the protected area
Unit 2 Reactor Building

During the plant tours, ongoing activities, housekeeping, security, equipment status and radiation control practices were observed.

Unit 1 Operations

McGuire Unit 1 began the reporting period in Mode 1 operating at 100 percent reactor power and operated at or about that power level until January 28. On that morning, the 1B main feedwater pump tripped when a suction pressure instrumentation line failed. A turbine runbac[illegible] failed to initiate upon the loss of feed pump due to a failed diode in th[illegible] runback circuitry. The unit subsequently tripped on steam generator 1B [illegible]-lo level.

The unit was subsequently recovered and ent red Mode 1 at 11:09 p.m., on the evening of January 30. The unit was paralleled to the grid and power held to 30 percent to allow secondary chemistry to be brought into specification. The unit's power was subsequently increased to 100 percent and maintained at that level until February 5, when the unit apparently tripped on negative high flux rate. This trip is discussed in detail in paragraph 7.

During the trip recovery, two engineered safeguards features actuations occurred. These events are discussed in paragraph 12. It was also determined that a wiring modification on the solid state protection system for Unit 1 had been incorrectly installed thus rendering the reactor trip breakers inoperable for Unit 1. This event is discussed in paragraph 11. Following correction of the modification the unit was restarted reaching criticality at 6:18 a.m., on February 7. Reactor power was subsequently

increased to and maintained at or about 100 percent until February 21, when power was reduced to 90-95 percent to maintain generator hydrogen temperature within limits (one cooler was valved out due to a leak). Power was maintained between 90-95 percent until March 8, when power was reduced to optimize outage scheduling. The unit was subsequently operated between 55-62 percent throughout the duration of the report period.

Unit 2 Operations

McGuire Unit 2 began the reporting period in Mode 1 operating at 100% reactor power. The unit was maintained at or about that power until 8:54 a.m., on January 25, when unit shutdown was begun to facilitate a refueling outage. The unit was shutdown and cooled down entering Mode 5 at 10:05 p.m., on January 26. The unit was maintained in Mode 5 until February 7 when the unit entered Mode 6.

Detensioning of the Reactor Vessel Head was complete at 3:00 a.m. on February 8. Core alterations commenced at 3:40 p.m., on February 16.

Fuel removal was completed at 2:45 p.m., on March 3. The unit remained defueled until March 20 when fuel reload was initiated.

6. Reactor Trip of January 28

On January 28, when Unit 1 was operating at 100 percent reactor power, an instrument air line failure to the B main feedwater (CF) pump suction pressure transmitter caused the loss of B CF pump on apparent low suction pressure. A turbine runback signal from loss of this feedpump failed to initiate a turbine runback due to a bad diode on a card in the turbine electro-hydraulic control. Operators attempted a manual turbine load reduction but were unsuccessful and a reactor trip occurred on lo-lo B steam generator level. After the trip some problems were encountered with B and C steam generator Pressure Operated Relief Valves (PORV). These valves failed to close for 4 minutes and 25 seconds respectively. A faulty pressure transmitter on B steam generator pressure caused the delay in closing the B steam generator PORV. The resultant inventory loss and void collapse caused B steam generator level to drop below its narrow range scale for approximately 6 minutes. The resulting cooldown caused pressurizer level to fall below the letdown isolation setpoint. A second charging pump was started, pressurizer level was recovered and letdown reestablished.

Following the trip the check valve in the Turbine Driven Auxiliary Feed Pump (TDAFP) line to the "C" steam generator failed to seat when the TDAFP was being realigned to the A and B steam generators. The valve was subsequently isolated, however a large portion of motor driven auxiliary feedpump flow to the "C" steam generator was backfeeding into the TDAFP suction line through the check valve prior to isolation. Further discussion related to backleakage of auxiliary feedwater check values is contained in paragraph 15.

7. Reactor Trip of February 5, 1985

On February 5, 1985, a Unit 1 reactor trip occurred on what appeared to be a High Negative Flux Rate. Unit 1 was at 94 percent reactor power in steady state operation. Power had been reduced to this level to facilitate the resetting of the High Negative Flux Rate trip setpoints per Westinghouse recommendation as discussed in paragraph 9. At the time of the trip, three of the four Power Range Nuclear Instruments had been reset; preparations were underway to reset the fourth. No instrumentation and electrical work was in progress at the time of the trip. Two design engineering personnel were performing a visual inspection of the nuclear station modification installed in the Unit 1 Reactor Trip Breaker Cabinets discussed in paragraph 11.

There is no conclusive evidence to indicate that changing the High Flux Rate trip setpoints contributed to the reactor trip. A reenactment of the visual inspection which design engineering was conducting did not result in opening of the reactor trip breakers. Efforts to determine the exact sequence of events was hampered by the fact that the events recorder points for the reactor trip breakers were out of service as had been noted on the reactor trip which occurred on January 28. A work request to correct this problem had been issued but the repairs had not been affected.

It cannot be determined conclusively whether one or both of the reactor trip breakers opened causing the rods to fall and thus causing a High Negative Flux Rate trip indication or whether an actual High Negative Flux Rate signal opened the reactor trip breakers.

Since the cause of the reactor trip could not be determined, an independent review was performed per Station Directive 3.1.10. Licensee personnel evaluated the occurrence and could not determine the cause of the trip. The Station Manager made the decision to restart the unit with instructions to monitor the High Flux Rate trips with recorders.

8. Diesel Generator (D/G) 2A Valid Failure

Diesel Generator (D/G) 2A experienced a valid failure on January 31, 1985. The failure occurred as a result of a low lube oil pressure trip while Operations personnel were performing a 24 hour run test in preparation for an engineered safety features (ESF) test. After the trip, inspections were made to determine the cause for low lube oil pressure. When no cause was found, D/G 2A was restarted for additional troubleshooting. Due to abnormal vibration in the engine, the run was terminated and the D/G was declared inoperable.

An inspection of the main bearings following the shutdown of the D/G showed severe damage had occurred to five of ten main bearings. The bearing deterioration appears to be the result of a mechanical failure. Preliminary investigations indicate that damage was not due to oil starvation of the bearings. A final determination of the cause of the bearing failure can not be made until the licensee completes all inspections and measurements during the course of repairs.

Details concerning the D/G 2A failure is covered in Report No. 50-369/85-13 and 50-370/85-12.

9. Westinghouse Determination of Incorrect Rod Drop Time Specifications

On February 1, 1985, Westinghouse notified the licensee that McGuire's TS 3.1.3.4 allows a rod drop time of 3.3 seconds. This does not coincide with Reactor Trip System Instrumentation Trip Setpoints stipulated in Table 2.2-1 Item 4. This specification if corrected would require Power Range, Neutron Flux, High Negative Rate, Trip Setpoint of less than or equal to 5 percent of Rated Thermal Power with a time constant greater than or equal to 2 seconds. It was identified during a review of this issue that the applicable TS 2.2.1, Table 2.2-1, Item 4 is incorrect in that it specifies a trip setpoint of greater than 5 percent rated thermal power when it should state less than 5 percent rated thermal power. From Westinghouse's calculations a trip setpoint of less than or equal to 5%/2 seconds would require a rod drop time of less than or equal to 1.7 seconds.

At the time of the notification, McGuire Unit 1 was in Mode 1 operating at 100 percent and Unit 2 was in Mode 5 at the beginning of a refueling outage. A licensee evaluation of the previous Unit 1 Rod Drop surveillance revealed that McGuire Unit 1 rod drop times were 1.47 seconds. This is less than 1.7 seconds as required by the new Westinghouse determined requirements. On February 5 and 6, 1985, the Unit 1 Power Range Neutron Flux High Negative Rate trip setpoints were adjusted to 2½ percent of rated thermal power with a time constant of greater than or equal to 2 seconds in accordance with Westinghouse recommendations. Unit 2 setpoints will be set at a similar value prior to the end of this refueling outage.

10. Inoperable Fire Barrier

On February 2, licensee personnel were preparing to implement a Nuclear Station Modification when a ½ inch by 1½ inch hole was discovered under control board 2MC11. This hole connected the Unit 2 side of the Control Room to the Unit 2 cable spreading room underneath the control room. It was subsequently determined that a similar hole existed on the Unit 1 side in the equivalent area under 1MC11, but this hole was appropriately sealed by fire barrier foam. A licensee evaluation failed to determine when or why the hole was drilled.

TS 3.7.11 requires that all fire barrier penetrations (walls, floor/ceilings, cable tray enclosures and other fire barriers) separating safety-related fire areas or separating portions of redundant systems important to safe shutdown within a fire area and all sealing devices in fire rated assembly penetrations (fire doors, fire windows, fire dampers, cable piping, and ventilation duct penetration seals) shall be OPERABLE at all times. The fire barrier between the Control Room and the Cable Spreading Room was found by the licensee to have been inoperable for an indeterminate amount of time. Upon discovery of the hole the licensee promptly took compensatory measures and established continuous fire watches. The above event is a licensee identified violation and will not be cited since it meets the NRC Enforcement criterion in 10 CFR 2 Appendix C.

11. Improper Installation Of Wiring During Modification Of Train "A" and "B" Reactor Trip And Bypass Breakers

During the implementation of a Nuclear Station Design Modification (NSM) on the Unit 2 Reactor Trip and Bypass Breakers, NSM MG-2-285 Rev. 0, (commitment to SSER No. 7, Section D.5.3) the technician responsible determined that the NSM was not clear about the required cable separation for Train A and Train B wiring components. As a result the technician did not perform the modification but referred the problem to his supervisor. Subsequent evaluation determined that the same design modification had been performed on Unit 1 on March 26, 1984, NSM MG 1376 Rev. 0.

A Quality Assurance inspection of the Unit 1 Reactor Trip and Bypass Breakers determined that the Train A and Train B separation criteria was not met, in that a Train A wire was routed in a Train B wire track. The NSM's were not clear about required cable separation or which wiring tracks within the trip breaker cabinets to use for the A and B trains.

10 CFR 50, Criterion III states in part that "...design control measures shall provide for verifying or checking the adequacy of design..." and further states that "design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design..." The original design incorporates 10 CFR 50, Appendix A, Criterion 21 - Protection System reliability and testability, which states in part that redundancy and independence designed into the protection system shall be sufficient to assure that no single failure results in loss of the protection function.

Contrary to the requirements of 10 CFR 50 Appendix B, Criterion III, NSM MG-1376 Rev. 0 was incorporated into the Unit 1 Reactor Trip Breaker cabinetry without adequate design control measures, in that no guidance was provided to ensure that wiring separation criteria would be met. The above constitutes a violation 369/85-06-01.

12. Unplanned Actuation of Engineered Safeguards Features (ESF)

On February 6, 1985, while Unit 1 was in Mode 3, an unplanned auto actuation of Engineered Safeguards Features occurred when procedural prerequisites were not met during the performance of PT/1/A/4601/03, Protective System Channel III Functional Test (Unit 1), while a channel undergoing negative rate trip adjustment was simultaneously out-of-service. A reactor trip and turbine driven and motor driven auxiliary feedwater pumps initiation occurred.

Procedure steps 6.1 and 12.3 of PT/1/A/4601/03 were not met in that reactor protective system instrumentation for Channel III A, B, C and D steam generator lo-lo levels were in test with the bistables tripped while Channel IV of the Nuclear Instrumentation (NI) power range was in test for

adjustment of the negative rate trip per Procedure IP/0/A/3207/03K as discussed in paragraph 9. When power range Channel IV was increased to 100 percent, the subsequent increase of steam generator lo-lo level trip setpoint reached the actual steam generator level initiating the ESF actuation.

A few minutes later another inadvertent ESF actuation occurred resulting in the automatic start of the A & B motor driven auxiliary feed pumps. An electrician accidentally depressed a limit switch inside the reactor trip breaker "A" (RTA) cabinet. After the cause was determined and corrected, the plant was realigned to a normal shutdown lineup. The unit was in Mode 3.

An evaluation of these incidents revealed the following concerns. Procedural steps specifying that only one channel be tested at a time were violated for both PT/1/A/4601/03, Protective System Channel III Functional Test (Unit 1), steps 6.1 and 12.3 and IP/0/A/3207/03/K, Nuclear Instrumentation System (NIS) Power Range Drawer Calibration Procedure, Prerequisite 4.1. Furthermore, Control Room operators knew about this simultaneous work and permitted it to be done.

TS 6.8.1 requires that written procedures shall be established, implemented, and maintained covering the activities referenced in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978 which includes the Nuclear Instrumentation System. Contrary to this requirement, procedural steps as noted above of PT/1/A/4601/03 and IP/0/A/3207/03K, were not correctly implemented. This item in conjunction with the item in paragraph 14, is a violation 369/85-06-02: Failure to Follow Procedure.

13. Diesel Generator Surveillance Inadequacies

On February 15, 1985, the licensee identified to the resident inspector that McGuire has been in violation of TS Table 4.8-1, Diesel Generator Test Schedule. This violation involved an interpretation of the criteria for determining the number of failures and number of valid tests as identified in the TS and Regulatory Guide 1.108, Rev. 1. This criteria is based on a per unit basis and the McGuire personnel had based their criteria on a per diesel generator basis. Based on this interpretation, D/G 1A had a valid failure on February 28, 1984, with unit start attempt 116 and a second valid failure on July 22, 1984, with unit start attempt 133. On July 22, 1984, the surveillance frequency for D/G 1A was increased to once every 14 days, however, D/G 1B remained on a 31 day surveillance cycle. For Unit 2, D/G 2A had a valid failure on July 8, 1983, with unit start attempt 9, D/G2B had a valid failure with unit start attempt 41. Since the criteria was not being correctly interpreted at this time, it was not recognized that the surveillance frequency for Unit 2 D/Gs was required to be increased to a frequency of 14 days. Subsequently D/G 2B had another valid failure with unit start attempt 42 on July 21, 1984, which should have increased the surveillance to seven days for Unit 2 D/Gs. Action was taken at this time to increase

surveillance frequency to D/G 2B to 14 days. On September 11, 1984, D/G 2A again had a valid failure with unit start attempt 49. At this time D/G 2A surveillance was increased to 14 days, when this was actually the 4th unit failure and the frequency should have been increased to a 3 day interval. On January 31, 1985, D/G 2A had another failure which caused the diesel to be declared inoperable and required disassembly and maintenance to be performed which is still in progress at this time. On or about February 12, 1985, McGuire personnel recognized the interpretation problem and implemented the 3 day requirement on D/G 2B for Unit 2 and the 14 day requirement on D/G1B for Unit 1. This item is identified as a violation 369/85-06-03, 370/85-06-01: Failure to Correctly Implement TS Surveillance Requirement 4.8.1.1.2.a.

14. Nuclear Service Water Valve Misalignment

During a routine tour of Unit 2, on January 23, 1985, the inspector identified that 2RN-158 (RN pump 2B motor cooler inlet isolation) was not "locked open" as required by OP/2/A/6400/06, Nuclear Service Water System. This observation was provided to the Shift Supervisor who took appropriate corrective action. Subsequent investigation by McGuire station personnel as described in Non-Routine Event Report No. 2-85-03 and Licensee Event Report 370/85-01 identified that this valve had apparently not been locked since October 16, 1984. These reports concluded that this occurred as a result of not adequately following OP/0/A/6100/09, Removal and Restoration (R&R) of Equipment. The R&R was issued October 15, to isolate RN pump 2B for maintenance. On October 16, the R&R was cleared but the valve was returned to an "open" position in lieu of "locked open" as prescribed by OP/2/A/6400/06. This failure to "lock open" this valve resulted in TS surveillance 4.7.4 not being accomplished for this valve since this valve is not checked by the monthly surveillance test for this system. This item in conjunction with the item in paragraph 12 is identified as a violation 370/85-06-02: Failure to Follow Procedure OP/0/A/6100/09, Removal and Restoration of Equipment For Valve 2RN-158.

15. Auxiliary Feedwater Overpressurization

The events relevant to auxiliary feedwater suction piping overpressurization were analyzed in this, a followup inspection of an unresolved item (50-369/85-08-07) identified in an earlier inspection report. There are two concerns pertaining to this area. Both of these concerns are associated with a failure to take appropriate corrective action in a timely manner. The first concern is the lack of notification to plant operations personnel of a potential problem with backleakage past feedwater check valves which could potentially cause a degradation in the capability of auxiliary feedwater pumps to fulfill this safety function. This was identified by a design engineering memorandum in which a water hammer event occurred at a foreign plant due to leaking check valves and piping configuration. In this memo the engineer recommended a provision to provide indication of leakage past the check valves and also recommend that operations perations personnel should be cautioned about this potential problem. In addition, Westinghouse

notified Duke Power Company (DPC) of the above backleakage problem in a letter dated November 11, 1981. This letter also proposed modifications to detect leakage and modify operating procedures to minimize this potential problem.

A January 1984, report was issued discussing operability of industry auxiliary feedwater pumps due to backleakage. This report provided specific procedural guidance on how to detect backleakage and stated that actions to mitigate the situation should be provided. A DPC memorandum to various superintendents dated June 22, 1984, identified among other recommendations that operations should initiate as soon as possible a walkdown inspection once per shift.

The second concern is a failure to adequately take prompt corrective action for the improper installation of the turbine driven auxiliary feedwater pump (TDAFWP) discharge stop check valve (1CA-22). On August 25, 1981, the suction piping of the TDAFWP was overpressurized. Contributing to this problem as reported in Reportable Occurrence Report RO-369/81-136 dated September 8, 1981, was that the stop check valve in the pump discharge was mounted in a horizontal pipe with the cylinder in a horizontal position so that closure is not aided by gravity. Although this was identified as a contributing factor, corrective action was not taken to correct this deficiency. Following the January 1984 industry report and review by the licensee, a DPC memo dated June 22, 1984, identified that stop check valves were installed in a horizontal position and McGuire Projects should initiate a Nuclear Station Modification (NSM) to correct this discrepancy. On August 26 and again on August 30, 1984, the TDAFWP suction piping was overpressurized due to back leakage past the check valves and the stop check valve. It was not until September 5, 1984, that NSMs were originated to install a monitoring system to determine leakage past the check valves and to correct the installation of the stop check valves, although this problem was identified on various occasions since 1981.

10 CFR 50, Appendix B, Criterion XVI as implemented by Duke Power Company (DPC) Topical Report, Quality Assurance Program Duke-1-A, Amendment 7, Section 17.2.16 requires that conditions adverse to quality be promptly identified and corrected and that the identification of the significant condition, the cause of the condition and the corrective action shall be documented and reported to appropriate levels of management.

Contrary to the above, conditions adverse to quality were not promptly identified and corrected, as detailed below. An occurrence on Unit 1 as reported in RO-369/81-136, caused overpressurization of the suction side of the turbine driven auxiliary feedwater pump. Identified as contributing to this problem was the stop check valve on the outlet of the pump being mounted in a horizontal position which prevents the closure of this valve to be aided by gravity as designed. Furthermore, on November 11, 1981, Westinghouse notified DPC of a potential problem concerning the design of

the auxiliary feedwater pump discharge piping and valve arrangement such that damage could occur which would compromise the safety-related function of the auxiliary feedwater system. Westinghouse in this letter, recommended system modifications and an operating procedures amendment to detect and correct this problem.

No actions were taken on these items identified above until September 5, 1984, when NSM 1-1705 and NSM 2-0550 were generated to replace the existing stop check valves with a different design valve, and NSM 1-1706 and NSM 2-0551 were generated to install a temperature monitoring system as recommended by Westinghouse. As of March 12, 1985, NSM 1-1706 and NSM 2-0551 are in process of being installed and NSM 1-1705 and NSM 2-0550 are scheduled for outages in 1986 due to material delivery.

This item is identified as a violation 369/85-06-04, 370/85-06-03: Failure to Take Prompt Corrective Action to Notify Operations Personnel of Potential Degradation of Auxiliary Feed Water System and Correct Improper Installation of TDAFWP Discharge Stop Check Valve. This violation is applicable to both units. This item closes unresolved item No. 50-369/85-08-07.

16. Containment Integrity

On February 19, 1985, valve 2SA-1 (the steam generator (S/G) 2C steam line to the turbine driven auxiliary feedwater pump isolation valve) was disassembled for maintenance. This created a possible flow path between inside containment and the interior doghouse. The valve was discovered disassembled by the licensee on February 21, 1985, at 3:12 p.m. Between these times, core alterations were made. TS 3.9.4 requires that containment integrity be maintained during core alterations or movement of irradiated fuel within containment. Core alterations are defined in TS definition 1.9 as the movement or manipulation of any component within the reactor pressure vessel with the vessel head removed and fuel in the vessel. Suspension of core alteration shall not preclude completion of movement of a component to a safe conservative position. The valve being disassembled, in conjunction with S/G 2C secondary side being open to containment atmosphere provided a flow path directly from containment, through the S/G secondary side, through the valve to the "dog house" (piping penetration room), directly to the outside environment.

Two possible flow paths into S/G 2C existed inside containment. The sludge lance cover plates were removed but the ports were taped closed with plastic for housekeeping. These plates cover four two-inch ports and two six-inch ports. A flow path also existed from containment atmosphere into the feedwater line of S/G 2C. 2CF-27, a sixteen-inch check valve was disassembled for maintenance, but plastic was taped over the valve body for housekeeping. Operations personnel believe the containment purge ventilation system (VP) was operating throughout the time 2SA-1 was open. This created a slight vacuum within containment, ensuring any leakage would have been into containment.

The following steps are used in scheduling work during an outage:

a. The Outage Coordination group make a schedule of work to be performed during an outage.

b. The Operations Unit Coordinator reviews the schedule.

c. Planning personnel schedule work requests using the Outage Coordination group's schedule as a guideline.

d. Each work request is sent to the shift supervisor for clearance to begin work.

The following occurred when scheduling the work on 2SA-1:

a. The work request description for 2SA-1 was typed in Project 2 as "2SA-11".

b. Prior to core alterations, Operation staff personnel and Outage Coordination personnel reviewed the outage schedule. The work on 2SA-1 was not identified as a potential containment integrity problem due to the incorrect entry.

c. Planning personnel scheduled WR 120293OPS on February 18.

d. The Assistant Shift Supervisor signed the "clearance to begin work" line on WR 120293OPS.

Once the work on 2SA-1 was scheduled, the Assistant Shift Supervisor was the only control point to stop the work. It is not realistic to expect a shift supervisor to catch every work request that could cause a containment integrity problem during an outage because: (1) there are a large number of containment penetrations and different ways to isolate each one (the procedure used to verify containment integrity, PT/2/A/4700/02C, is 62 pages long) and (2) the shift supervisor has a large number of work requests on which to give clearance. The shift supervisors must depend on the Outage Coordination group, the Unit Coordinator, and Planning to control scheduling work on equipment that can potentially affect containment integrity.

The Assistant Shift Supervisor stated that when he saw the work request on 2SA-1, he did not realize it could affect containment integrity. He saw that 2SA-1 could be worked on using an existing tag out (block tag out 85-F) so he signed the clearance line on the work request.

Corrective action to prevent future occurrence will include modifying work request entries on outage schedules to note that the item is a "Potential Containment Integrity Item." In future outages procedures will be modified to reduce the likelihood of this event occurring by involving the Outage

Coordination Group, the Unit Coordinator and the Planners such that a typographical error or oversight will be determined on a subsequent review by one of these groups prior to sending the work request to operations for clearance to begin work.

The above event is a licensee identified violation and will not be cited since it meets the NRC enforcement criterion in 10 CFR 2, Appendix C.

17. Containment Pressure Control System (CPCS)

Subsequent to identification by the licensee, the inspector conducted a review of TS 3.3.2, Engineered Safety Features Actuation System Instrumentation, specifically the Containment Pressure Control System (CPCS). The function of the CPCS is to preclude depressurization of containment by terminating containment spray and air return fans when they are no longer required. TS Table 3.3-4 identifies the CPCS trip setpoint as &0.25 psid for a start permissive and termination function. Table 3.3-3 identifies for CPCS that for both the start permission and termination function there are four total channels per train, implying a total of eight separate channels (four for start permissive and four for termination). In actuality there are a total of four channels per train to perform both functions. Also Table 3.3-3 lists that two channels per train are required to trip. This is in error. There are four pressure switches per channel: one switch provides on an increasing pressure in containment, a permissive signal to allow startup of the containment spray (NS) pump in that train, this switch also provides an automatic trip signal if the spray pump is running and containment pressure decreases to 0.25 psid; one pressure switch, on an increasing pressure in containment provides a permissive signal to the NS pump discharge valves, on a decreasing pressure of 0.25 psid this will automatically shut these valves; one pressure switch provides a start permissive signal for the Air Return and Hydrogen Skimmer Fan and will stop the air return and Hydrogen Skimmer Fan on a decreasing pressure; and the fourth pressure switch will provide a permissive signal for the hydrogen skimmer fan discharge valve and the Air Return Fan damper, and will shut the damper and valve on a decreasing pressure.

Table 3.3-3 also requires that CPCS must have a minimum of three channels per train for operation. However, any failure of an individual pressure switch would render that train inoperable, therefore all four pressure switches should be required. The action statement for CPCS allows power operation to continue with one less than the total number of channels if (a) the channel is placed in the tripped position - there is no tripped position for this instrument, and (b) the channel may be bypassed for up to two hours for surveillance testing of other channels - there is no bypass function for this channel.

The design for this system allows valves to be shut while pumps and/or fans are running, which could cause damage to the component. The plant currently operates under a TS interpretation which results in declaring an associated component inoperable if any one or more of the four channels in that logic train is inoperable.

This item is identified as Unresolved Item (369/370-85-05): Resolution of Containment Pressure Control System Design Questions, Pending Additional Review By Regional and NRR Design Engineering Personnel.

18. Surveillance Testing

The surveillance tests categorized below were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy. The completed test procedures examined were analyzed for embodiment of the necessary test prerequisites, preparations, instructions, acceptance criteria, and sufficiency of technical content. The selected tests witnessed were examined to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration completed and test results were adequate. The selected procedures perused attested conformance with applicable TS and procedural requirements, they appeared to have received the required administrative review and they apparently were performed within the surveillance frequency specified.

Surveillances

PT/1/A/4600/03E	Quarterly Surveillance Items
PT/2/A/4600/01	RCCA Movement Test
PT/1/A/4350/02B	Diesel Generator 1B Operability Test
PT/2/A/4150/16	Steam Generator Temperature Checklist
PT/2/A/4200/02C	Containment Integrity Verification During Core Alterations
PT/1/A/4204/02	ND Valve Stroke Timing
PT/1/A/4203/02	NB Valve Stroke Timing
PT/1/A/4451/02	VB Valve Stroke Timing
PT/1/A/4405/02	YM Valve Stroke Timing
PT/1/A/4208/01B	NS Pump 1B PERF Test
PT/1/A/4208/01A	NS Pump 1A PERF Test
PT/1/A/4403/01A	RN Train A PERF Test
PT/1/A/4252/01A	Motor Drive Aux Feed 1A PERF Test
PT/1/A/4209/01B	NV Pump PERF Test
PT/0/A/4209/01C	Standby Makeup Pump PERF Test
PT/1/A/4252/01	Aux Feed Pump #1 PERF Test
PT/0/A/4457/01A	Control Room Chilled Water Pump 1 PERF Test
PT/1/A/4601/08A	SSPS Train A Periodic Test
PT/1/A/4206/01A	NI Pump 1A PERF Test
PT/1/A/4601/03	Proctive System Channel III
PT/0/A/4601/07A	A reactor Trip Breaker Response Test
PT/0/A/4601/07B	B Reactor Trip Breaker Response Test

19. Maintenance Observations

The maintenance activities categorized below were analyzed and/or witnessed by the resident inspection staff to ascertain procedural and performance adequacy. The completed procedures examined were analyzed for embodiment of

the necessary prerequisites, preparation, instruction, acceptance criteria and sufficiency of technical detail. The selected activities witnessed were examined to ascertain that where applicable, current written approved procedures were available and in use, that prerequisites were met, equipment restoration completed and maintenance results were adequate. The selected work requests/maintenance packages perused attested conformance with applicable TS and procedural requirements and appeared to have received the required administrative review.

Work Request	Equipment
65401	Battery EVCA
85953	Train B VX
93356	Train B VC
65320	Train B VC
41203	RF Pump C
123097	S/G C Narrow Range Level
119109	Loose Pails Detector
85884	Valve 1 SA 49
039480	Turbine Driven Auxiliary Feedwater
950119	A Train VC
93296	A Train VE
123349	Turbine Stop Valve TV#1
040175	Containment Pressure Channel III
03975	FWST Level
123092	Repair as Necessary "B" S/G PORV (ISU-13)
122989	Repair 1CA-49 Check Valve
123014	D/G 1A Cylinder #2L Bad Temperature Indicator Check and Repair

20. IE Circulars, Construction Deficiency Reports and Bulletin Closeout

The following IE Circulars and Construction Deficiency Reports are being closed based on review of these items conducted at Region II:

Docket Number 50-369

CDR 82-06	78-CI-18
CDR 82-72	80-CI-03
CDR 83-15	80-CI-04
CDR 83-46	80-CI-13
	80-CI-15
	81-CI-13
	81-CI-14

Docket Number 50-370

CDR 81-06	81-CI-12
CDR 83-01	81-CI-13
CDR 83-03	81-CI-14
CDR 83-07	
CDR 83-27	

IE Bulletin 79-07, Seismic Stress Analysis of Safety-Related Piping, is considered closed for the purposes of the Regional Inspection Program. This closure does not affect the status of any NRR evaluations. Related inspection followup will be performed as required by IE Bulletin 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems.