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REGION I

Report No. 50-219/88-23

Docket No. 50-219

License No. DPR-16 Priority -- Category C

Licensee: GPU Nuclear Corporation
1 Upper Pond Road
Parsippany, New Jersey 07054

Facility Name: Oyster Creek Nuclear Generating Station

Inspection Conducted: July 31, 1988 - September 10, 1988

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Approved By: C Cowgill III 9/27/88
C. Cowgill, Chief, Reactor Projects Section 1A Date

Inspection Summary:

Areas Inspected: Routine inspections were conducted by the resident inspectors and one region-based inspector (372 hours) of activities in progress including plant operations and startup, radiation control, physical security, maintenance and forced shutdown work activities. In addition, inspectors reviewed isolation condenser system operability issues, Emergency Service Water (ESW) system In-Service Test (IST) results and baselining methodology, MSIV 5% closure tests, re-work procedure requirements and drywell air lock testing. The inspectors also observed portions of the quarterly emergency drill, witnessed MOVATS testing and reviewed operational experience during hot weather.

Results: One apparent violation was addressed involving isolation condenser system operability. Concerns were developed during review of isolation condenser system operability, including adequate Local Leak Rate Test (LLRT) procedural steps to return valves to the proper lineup and operator adherence to valve lineup verifications. Review of "B" isolation condenser activities resulted in concerns regarding leak tightness of the isolation valves, continued thermal binding of the isolation condenser condensate return valve (V-14-35) and the licensee's ability to solve this problem, proper control room log keeping, recognition and reporting of events, and the temperature anomaly associated with the isolation condenser steamlines. Several licensee improvements in ESW baselining were made.

SUMMARY AND OVERVIEW

The plant shut down on July 9 to repair a Main Steam Isolation Valve (MSIV). On completion of the repairs, a plant startup on August 11, 1988 was performed from unplanned outage 11-U-7, and the plant reached power operation on August 12, 1988.

On August 23, the "B" Emergency Condenser steam inlet valve was placed on its backseat for a packing adjustment. Subsequent post maintenance testing showed that the valve operator motor had failed. The motor was replaced, post maintenance testing was performed, and the Emergency Condenser was declared operable on August 28.

During the surveillance testing performed on August 28, an operator valving error caused a brief initiation of the Emergency Condenser. This resulted in a minor plant transient, and it became apparent that the condensate return valve was now leaking as indicated by Emergency Condenser shell side temperature increasing to 212 degrees and by observing water vapor at the shell vent. Operator action to continually add water was necessary to maintain shell water level above the low level alarm.

On August 29, the licensee closed the redundant condensate return isolation valve in order to trouble shoot the leaking valve. With both condensate return valves closed, the shell side temperature remained at 212 degrees, and the makeup rate of water to the condenser shell remained essentially the same at about 15 gallons per minute, indicating both condensate return valves are leaking. The system was returned to service with these valves leaking, following analysis of potential consequences of a tube leak.

During additional licensee evaluations associated with the isolation condensers, it was determined that the "A" isolation condenser had not been properly aligned for service following maintenance during an August shutdown.

This report also describes other activities and test occurring during the inspection period. Those are listed in the Table of Contents.

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ATTACHMENT

DETAILS

1.0 Inadvertent "B" Isolation Condenser Initiation

1.1 Event Description

During a valve operability test of the "B" isolation condenser on August 28, 1988, at approximately 12:30 p.m., a licensed operator incorrectly performed a sequence of condensate return valve manipulations (V-14-35 and V-14-37), resulting in an initiation of the "B" isolation condenser for a few seconds. The operator immediately recognized the mistake and took appropriate action to close the valves. The licensee noted a 1 inch reactor vessel level increase and a 1% increase in reactor power as a result of this system actuation. The inspector reviewed this transient with the licensee and did not note any abnormal conditions other than those indicated below. The licensee subsequently made a four hour report via the Emergency Notification System, but was approximately an hour and ten minutes late in reporting the event. In addition, the control room log entries for this event were made approximately six hours after the isolation condenser initiation. The inspector discussed both the late event reporting and log entries with the licensee, who stated that these were a result of shift management not immediately recognizing the significance of the isolation condenser initiation. Operations management was informed of the event shortly after its occurrence. The inspector expressed concerns regarding the late log entries and noted implementation in timely logging of events should be emphasized. The licensee has already taken steps in providing guidance to operators on proper log entries. With regard to the untimely reporting of the event, the NRC will exercise its discretion and not issue a Notice of Violation for the licensee-identified vilation since all five conditions required by 10 CFR Part 2, Appendix C had been met.

The operability test on the "B" isolation condenser was conducted on August 28, 1988, to return the condenser to service after completion of maintenance on V-14-33, "B" isolation condenser steam line inlet isolation valve. This Maintenance was planned to repair a packing leak on V-14-33 with the valve on its backseat. In attempting to place the D.C. motor operated valve on its backseat, licensee personnel incorrectly used an A.C. amp probe. After several unsuccessful attempts to obtain the proper current reading while backseating the valve, a D.C. amp probe was used. It appears that this error in backseating may have damaged the valve operator motor. The licensee performed MOVATS testing of V-14-33, and determined that the valve motor should be replaced. The inspector witnessed portions of this testing. These maintenance activities including motor replacement and subsequent testing occurred from August 23-28, 1988, rendering the "B" isolation condenser inoperable during this time.

1.2 Valve Binding

The misoperation of valves V-14-35 and V-14-37 on August 28, 1988, appears to have caused a V-14-35 valve problem. V-14-35 has a history of thermal binding problems. In reviewing V-14-35 maintenance history the inspector determined that valve binding occurred in February, 1985 (inspector open item 219/85-06-02), and again in May, 1987. In response to the occurrence in February, 1985, the licensee disassembled the valve for a detailed internal inspection. This inspection was performed in October, 1985, for the purpose of identifying the root cause of the failure. Blue checks were performed on both seats and indicated 360 degrees contact. Nondestructive examinations (NDE) were performed on the inner and outer valve body, valve bonnet, valve body seats, valve discs, stem, guide rails, stuffing box and stuffing gland. The only deficiencies identified were linear indications in the valve stem, and the stem was replaced. Extensive valve internal measurements were made, but no deficiencies were identified. A manufacturer representative observed valve reassembly. The licensee concluded from this inspection that the root cause of valve failure was excessive binding from live loaded packing in combination with packing drying between valve operations. To address this, a bushing was fabricated to reduce stuffing box depth, thus reducing the amount of packing installed. The subsequent recurrence of valve binding in May, 1987, indicates that the root cause has not yet been identified and corrected. Open item 219/85-06-02 will remain open.

On August 23, 1988, the "B" isolation condenser was removed from service for V-14-33 maintenance activities. This action resulted in isolation of steam to the isolation condenser and subsequent cooldown of the isolation condenser. Normally, during a plant cooldown, operators would cycle V-14-35 every 100 degrees F to ensure the valve does not become thermally bound. In this situation, however, the licensee did not recognize that cycling valve V-14-35 would also be required as the isolation condenser cooled down separately. This coupled with the inadvertent initiation of the isolation condenser may have contributed to the mechanical binding of the valve.

1.3 Valve Isolation Operability

The initial inspector concern involved the constant water makeup to the "B" isolation condenser needed after the inadvertent initiation. The inspector was concerned that the significant makeup rate indicated substantial valve leakage or flow through V-14-35. In performing a simple thermal energy balance across the isolation condenser both the licensee and inspectors independently determined that approximately 18 gpm were flowing through the valve with approximately a 20 psi differential pressure. The main inspector concern centered around an isolation condenser pipe or tube break and the facility's ability to satisfy 10 CFR 100 limits when the valve would be required to isolate against a 1000 psi differential pressure. This would result in a much higher flow rate through valve V-14-35. The inspector expressed his concerns to the licensee who immediately closed V-14-37, the redundant condensate return valve for V-14-35. The licensee had already begun plans to remove the isolation condenser from service and trouble shoot V-14-35 when the inspector discussed the concern with the licensee. Subsequent MOVATS testing of V-14-35 by the licensee determined that the torque switch setting was lower than required. During the MOVATS testing, the licensee found that the motor operator developed approximately 18,000 lbs of thrust in the closing direction. The minimum recommended closing thrust value is 21,302 lbs. The torque switch was increased to correspond to the requirements of Station Procedure 700.2.010, "Motor Operated Valve Removal, Installation, or Inspection (Elect)" and the required thrust values. This action, however, had no observable effect on the valves' leak rate.

The licensee performed 10 CFR 100 calculations for present and technical specification limits for reactor coolant iodine activity levels. These calculations satisfied 10 CFR 100 limits. In addition, the inspector obtained independent reg' l office calculations which corroborated the licensee's results.

1.4 Emergency Condenser Valve Testing

Technical Specification 3.8, Isolation Condenser, defines operability specifications for the isolation condenser steam inlet valves (V-14-30, V-14-31, V-14-32 and V-14-33) and the A.C. motor operated isolation condenser outlet (condensate) valves (V-14-36 and V-14-37), but does not address the D.C. motor operated isolation condenser outlet valves (V-14-34 and V-14-35). The basis for Technical Specification 3.8 refers to V-14-34 and V-14-35 stating that it is not necessary to test the redundant D.C. motor operated valves as these valves are normally in the closed position. Other than this reference to the D.C. motor operated condensate isolation valves, they are not specifically discussed. Since the intent of the specification is to address the isolation function of the valves, the specification should also address the isolation functions of V-14-34 and V-14-35. This warrants clarification to avoid operator and licensee confusion with regard to one of the design functions of the valves.

Operability testing on these valves only involves valve stroking and does not require any determination of leak tightness. In a letter to Director of NRR from Jersey Central Power and Light Company dated November 22, 1978, a request for partial exemption from the requirement of 10 CFR 50 Appendix J was forwarded including isolation condenser valves V-14-30 through V-14-37. In a reply letter dated March 4, 1982, the exemption for Appendix J testing was accepted as these valves do not provide an isolation function for a line break occurring inside the containment. These valves do, however, provide a reactor coolant pressure boundary isolation in the event of an isolation condenser tube rupture or an isolation condenser line break, both of which occur outside the primary containment. The allowable leakage for the emergency condenser isolation valves should be quantified to ensure valve integrity, and thus the isolation valves ability to perform their intended pressure isolation function.

In addition, other valves performing a similar function exist in the plant that are not leak checked. One set of valves in particular, the scram discharge volume (SDV) drain valves (V-15-121 and V-15-134) caused significant radioactive steam release in the reactor building when the licensee was unable to reset a scram on June 12, 1985 (see Inspection Reports 85-19 and 85-23). Unresolved item 85-23-05 questions why the SDV vent and drain valves are not part of the containment pressure boundary and, therefore tested in accordance with the requirements of 10 CFR 50 Appendix J. Management attention is required in addressing these issues.

1.5 Emergency Condenser Steam Line Temperatures

Emergency Condenser steam line temperatures are about 540 degrees F following startup and then gradually decline as condensate accumulates in the steam line. After the "B" isolation condenser initiation, the two steam line temperatures dropped from the 540 degrees F they were at, to 100 degrees F when removed from service, and then one recovered to about 300 degrees F and the other to about 200 degrees F following return to service. It would be expected that the ratures would have returned to a higher value with the condensate return valves leaking. This condition has not been explained to date. The licensee should assure themselves that this is not indicative of a potential degradation of isolation condenser performance.

2.0 "A" Isolation Condenser Inoperable

2.1 Event

In preparation to return the "B" isolation condenser to service on September 2, 1988, after testing of the condensate return valve, V-14-35, the licensee was evaluating the steam line temperature indications (see paragraph 1.5). As part of this evaluation, it was decided to verify that the isolation condenser vent valves were correctly positioned. The licensee chose to verify the vent valves for both the "A" and "B" isolation condensers as a matter of prudence. During this verification, it was determined by the licensee that while the manual vent valve for the "B" isolation condenser (V-14-2) was correctly positioned ("open"), the manual vent valve for the "A" isolation condenser (V-14-6) was not. V-14-6 was found in the "closed" position.

With the condenser vent path isolated, this would prevent the "venting off" of noncondensible gas from the isolation condenser steam supply piping and condenser tubes. Noncondensable gases adversely affect the ability of the isolation condenser to perform its intended function and could render the condenser inoperable.

Upon discovery, the licensee declared the "A" isolation condenser inoperable. Since the "B" isolation condenser was already inoperable for maintenance and evaluation, the plant was below the minimum functional capability for safe operation of the facility as defined in the plant technical specifications. A plant shutdown was initiated, reducing power at the rate of 25 megawatts electric per hour. Plant technical specifications require that both "A" and "B" isolation condensers be operable, with one condenser permitted to be out of service with the plant in the 'run' mode for a period not to exceed seven days. With both condensers out of service, plant technical specifications require the plant to be placed in "cold shutdown" within 30 hours.

The licensee opened the manual vent valve, V-14-6, to establish a vent path for the "A" isolation condenser, performed complete valve lineup verifications on both isolation condenser subsystems, and initiated calculations to determine the length of time required to vent the noncondensable gases prior to "A" isolation condenser being capable of performing its intended function.

The licensee notified the NRC duty officer at 12:26 p.m. on September 2, 1988 that both isolation condensers were not operable via the Emergency Notification System.

At 8:17 p.m. on September 2, 1988, both "A" and "B" isolation condenser subsystems were returned to service, and the plant shutdown was terminated at 82.5% power.

2.2 Event Review

The licensee reviewed the documentation concerning the isolation condenser vent valves in order to determine how valve V-14-6 was left in the wrong position. On August 10, 1988, the plant was started up following an unplanned outage. During this outage, maintenance was performed on the isolation condenser air operated valves and also on the main steam isolation valves. As part of post maintenance testing, the valves were tested for leakage per local leak rate test Procedure 665.5.003, "Main Steam Isolation Valve Leak Rate Test".

From documentation on these work activities, the licensee concluded that misinterpretation of a procedural step led to valve V-14-6 being left in the "closed" position. Since a complete valve lineup was not planned for this system, the licensee had to rely on procedures such as this and administrative controls to return valves to their required positions.

The licensee noted that this error on V-14-6 should have also resulted in V-14-2 (manual vent valve on "B" isolation condenser) being left in the closed position. This was not the case, as, V-14-2 was found "open" on September 2, 1988. The licensee, has to date, offered no explanation for how V-14-2 was opened.

The inspector independently reviewed the documentation available on activities associated with valve V-14-6. This documentation included tagouts and test documentation from Procedure 665.5.003, "Main Steam Isolation Valve Leak Rate Test".

A summary of the documented activities on valve V-14-6 is provided in Attachment I.

The inspector concluded that incomplete execution of step 7.72 of Procedure 665.5.003, resulted in valve V-14-6 being left in the closed position. The fact that valve V-14-6 was closed was documented during the August 4-5 performance of Procedure 665.5.003. The inspector determined that this step was inadequate in the direction it provided to the operators. It provided general rather than specific direction to "return all valves to their as found positions".

The inspector concluded that this procedure did not provide adequate control of valve positions in that valves were operated with no valve lineup to restore and verify their positions. The licensee review of this event came to similar conclusions.

From the available documentation, the inspector could not identify how valve V-14-2 was returned to the open position.

The licensee has stated that they will review all local leak rate test procedures for ambiguous steps and provide detailed valve lineups to restore valve positions.

The inspector also reviewed isolation condenser temperatures to determine what indications would be available to indicate that the vent paths were secured. Historical data for the steam line temperatures on the "A" isolation condenser showed no change after September 2, when the manual vent valve was opened. The inspector concluded that the vent status of the isolation condensers could not definitively be determined from steam line temperatures.

The licensee performed calculations to determine the length of time required for the "A" isolation condenser to be operable after opening the isolation condenser manual vent valve. These calculations were reviewed by the resident inspector. The licensee calculations determined that a vent time of approximately 7 hours was required to reduce noncondensable gases to less than 0.003% for restoration of heat transfer capability and elimination of water hammer potential. In addition, the calculations determined that 1% air by volume reduces the condensing coefficient by a factor of about 2 and that approximately 3.3 cubic feet of gas accumulated in the 22 days the "A" isolation condenser vent valve was closed. This represents approximately 3% of the steam supply line volume. The licensee is performing additional calculations to determine what the heat transfer capability would have been in this situation. In addition, the inspector questioned the bounding assumptions of these calculations and is awaiting the licensee's response. Specifically, a bounding condition stated that noncondensible gases in the steam line would be removed by a steam purging mechanism that assumed complete mixing of the steam and gases. Steam piping downstream of the isolation condenser vent, however, is no in the steam purging flow path. The inspector questioned if the mechanism for that portion of steam piping is more accurately described by a diffusion model; and, if the time for this gas diffusion to be completed would be bounded by the vent time calculations.

2.3 Conclusions

As a result of the valving error on V-14-6, the "A" isolation condenser was performed by the licensee to be inoperable from startup on August 10, 1988, until September 2, 1988, when the condenser was vented. In addition, the "B" isolation condenser was inoperable for valve maintenance from August 23, 1988, until August 28, 1988; and from August 29, 1988, until September 2, 1988. These combinations result in a total period of time when both isolation condensers were inoperable, during the run mode, of approximately 10 days. This is an apparent violation of Technical Specification 3.8.

Upon discovery, the licensee took prompt and effective steps to return the isolation condensers to an operable status, performed required actions delineated in the plant technical specifications and made the required notifications.

3.0 Emergency Service Water System In Service Test (IST) Rebaselining

During this report period, the licensee determined that the baseline data for the Emergency Service Water (ESW) pumps' 52A and 52B differential pressure (dp) were incorrectly determined in May 1988. ESW pump dp baseline data were used in Surveillance Procedure 607.4.003, "Containment Spray and Emergency Service Water Pump Operability and In Service Test". These baseline data were performed in May as a result of a change in the IST surveillance to establish a new baseline at 3200 gpm.

The licensee became aware of this problem in early August when the IST surveillances performed on the ESW pumps exceeded the high action limits for pump dp. In review of this discrepancy, the licensee hypothesized that the pump discharge pressure was taken in May with the discharge gauge was isolated. As a result of this review and the conclusion that the May baseline data was incorrect, the licensee established a corrected baseline on August 4.

During the followup of this event by the resident inspector, the methodology of how the May baseline data was obtained was questioned. The baseline was obtained by measuring discharge pressure at both full flow and at a flowrate of 3200 gpm. The engineer in analyzing the discharge pressure at full flow saw that it was consistent with past measurements. On this basis, the engineer concluded that the discharge pressure observed at 3200 gpm was accurate. Since the engineer did not compare this observed discharge pressure to the ESW pump curve, he did not realize the value was inaccurate.

After reviewing the methodology of obtaining baseline data, the licensee intends to implement the following changes in Administrative Procedure 125, Conduct of Plant Engineering:

1. The basis for all IST baselining shall be documented on Form 125.1 of Administrative Procedure 125.

2. When establishing a new baseline, the data obtained shall be compared to the pump curve to ensure that the pump's performance has not be degraded.

3. An independent verification shall always be required.

In addition, the licensee had previously identified a weakness in the ESW pump IST surveillance which may potentially result in the isolation of the discharge pressure gauge when taking data. The licensee intends to incorporate changes in this procedure to minimize any error or confusion.

The inspector had no further questions on the licensee's baselining methodology. The inspector, however, is still following up on other aspects of this issue.

4.0 Diesel Generator Control Circuitry

On August 1, a relay contact failure occurred in #1 Diesel Generator during the performance of a load test surveillance. Another contact-related failure had occurred five days earlier on July 27. As a result of the relatively short time period in which these two failures occurred and in light of the fact that many of the contacts in the Diesel Generators are over twenty years old, the inspector raised the question of whether or not these recent failures were indicative of an aging concern.

The first failure occurred while performing Surveillance Procedure 636.4.003, "Diesel Generator Load Test", on #1 Diesel Generator. The licensee postulated that a sequence fault associated with the peaking load control circuitry occurred when the "ST" contact had remained temporarily closed. This contact, however, would not have been in the control circuit if an actual emergency start had occurred and therefore would not have prevented the diesel from performing its design function.

The second failure occurred while also performing the diesel generator load test. During the normal shutdown sequence, the "UST" contact had failed to open, thereby preventing the trip of the idle speed governor. The backup trip, the "OTT" contact which opens after a longer time delay, opened to trip the diesel generator via the overspeed trip lever. This contact also would not have prevented the diesel generator from starting on an emergency actuation.

The licensee responded to the aging question by pointing out that the failure rate of contacts in the diesel generator were relatively low. This response was confirmed by the inspector through a review of #1 Diesel Generator's material history records. From the period May 1981, to July 1988, nine contact/relay replacements in #1 Diesel Generator were identified. The licensee further pointed out that a preventative maintenance plan had already been approved for the 12R outage. The licensee intends to check the resistances on all contacts in the diesel generators and compare them with an established threshold value. This check is intended to be an early identification of contacts which have a potential for failure. The inspector has no further safety concerns on this issue.

5.0 Core Bore Drilling

On August 8, the licensee confirmed through radiography that the drywell shell was damaged by core bore drilling. This damage was incurred while performing work to install a drywell cathodic protection system. The purpose of the drywell cathodic protection system modification is to arrest the drywell corrosion rate believed to be caused by water leakage from the reactor cavity seal area. The installation of this system involved the use of a 4-3/8" core bore tool to gain access to the sandpocket adjacent to the drywell by drilling through several feet of the concrete drywell shield wall. It is necessary to gain access to the sandpocket for placement of the anode portion of the system. During the drilling of the second hole, hole #6 in bay #11, the drywell was accidentally drilled a total of 2-1/2" at a 45 degree angle to the drywell surface. This distance corresponds to a maximum penetration of 1.81" normal to the drywell surface. The drywell shell thickness in this area is 2.9 inches. This resulted in questions regarding drywell integrity.

As an immediate corrective action, the licensee stopped all further core bore drilling in the drywell shield wall. A safety evaluation, including calculations was performed to demonstrate adequate drywell integrity to meet design requirements. The safety evaluation was reviewed by NRC Region I Specialists and found to be acceptable.

At the end of this report period, the core bore drilling remained suspended. The licensee is continuing to review this event to determine proper corrective actions necessary to recommence core bore drilling and to identify the root cause of this event. The resident inspectors will continue to follow the licensee's activities in this area.

6.0 Drywell Airlock Local Leak Rate Test

On August 8, 1988, the inspector became aware that a leak rate test of the drywell airlock had failed, troubleshooting/corrective actions were being taken, and the test was being conducted at a test pressure of 10 psig. This test was being performed in order to demonstrate primary containment integrity prior to pressurizing the reactor during plant heatup. Subsequently, a successful test was conducted using a test pressure of 10 psig.

The same day the inspector reviewed Procedure 665.5.005, "Drywell Airlock Leak Test", for the required test pressure. This procedure allows the test to be performed at either 10 psig or 35 psig (corresponds to accident pressure of 10 CFR 50 Appendix J), and directs that the local leak rate test engineer should be contacted to determine which test pressure was required. The inspector also reviewed plant technical specifications which specify that the drywell airlock be tested at a pressure of 10 psig. Since plant technical specifications indicate a test pressure of 10 psig, and since this was the test pressure being used in the field, the inspector concluded that this was the test to be used to demonstrate primary containment integrity. The inspector was concerned that primary containment integrity would not be shown per the requirements of 10 CFR 50, Appendix J.

The inspector contacted the local leak rate test engineer and indicated to him that in order to conform to the requirements of 10 CFR 50, Appendix J, a 35 psig test would be required. The local leak rate test engineer subsequently directed that a test be performed at 35 psig, and this test was satisfactorily completed before reactor startup and heatup to normal operating pressure. Once the test was performed at 35 psig, the inspector concerns were satisfied.

After the plant was pressurized to normal operating pressure, the licensee performed a drywell entry and inspection. After the inspection and use of the drywell airlock, it was again tested at a pressure of 35 psig. The inspector noted that a Technical Specification Change Request had previously been submitted by the licensee in order to more clearly specify the testing requirements on the drywell air lock.

The inspector had no further questions regarding this test.

7.0 Quarterly Emergency Drill

The inspector witnessed portions of the quarterly emergency drill conducted on August 23, 1988, and attended the licensee's critique following the drill. During the drill which involved two separate release points from two different elevations of the facility, the technical support center offsite dose computer was unable to perform the calculations. The release calculations were appropriately performed by the Emergency Offsite Facility by performing a separate calculation for each release point and adding the results. This was discussed with the Radiological Control Director who stated that they were contemplating increasing the computer's capacity so that separate release calculations could be conducted simultaneously. Presently no requirement exists to have the capability to perform a simultaneous computer calculation for separate release points, but the licensee considers this an improvement to their capabilities. The drill critique seemed to be beneficial for the participants and was constructive in determining problem areas. The inspector had no concerns.

8.0 Fuel Rod Defects

The licensee was informed by the new fuel fuel rod vendor that approximately 69 of the 220 new fuel assemblies for the upcoming 12R refueling outage could have manufacturing defects in one or more rods of each assembly. The defects have been characterized preliminarily as cracks forming on the outside wall of the fuel rods and propagating towards the inner wall. Presently the licensee plans to reconstitute fuel bundles to support the refueling effort and send the remaining bundles to the vendor for further examination. The vendor currently has determined that the potential defects do not represent a safety concern and does not plan a 10 CFR 21 report. The inspector will continue to follow the licensee actions.

9.0 MSIV Closure Test

On August 18, 1988, the inspector noted that during the conduct of a 5% Main Steam Isolation Valve (MSIV) closure test on NS04A, the annunciator, main steam valves off normal, was received indicating that the valve is less than 90% full open. The inspector discussed this with the control room and later operations management to determine if the significance of this alarm was appropriately considered. The inspector's concern was that potentially a reactor protection system (RPS) input could be malfunctioning. If the annunciator was valid and the valve had traveled 10% then a half scram should have been received. The operators were also concerned about this and attempted to find an electrical print depicting the circuitry coming from the MSIV limit switch but could not find the appropriate drawing in the control room. The following morning operations management and electrical maintenance personnel reviewed the circuitry drawing obtained from the electricians and determined that the microswitch for the annunciator contact was dirty and required burnishing. This was performed later that day and the RPS input verified to be operable. During the time from the initial valve testing to the subsequent determination the following day, the control room had not clearly determined that the MSIV RPS input was functional. The licensee stated that shift management had determined that the problem was only associated with the annunciator and not the RPS input, but without having performed a test to verify operability, it is difficult to clearly determine RPS input operability. The inspector had no other concerns other than the technical pursuit and resolution of the problem by the operating shift.

10.0 Radiation Protection

10.1 High Radiation Area Door Unlocked

On August 30, the licensee discovered that a locked high radiation area door was left opened and unattended. The fill aisle door, HR 38, which is located on the 23' elevation of the new radioactive waste building was left opened approximately 15 hours. The licensee's initial corrective actions were to verify the fill aisle unoccupied and to close and lock the fill aisle door.

The radiological investigative report on this occurrence ascertained that a contractor was responsible for leaving the fill aisle door unlocked. The licensee intends to conduct a critique of this occurrence. The inspector is satisfied with the immediate corrective action. A future inspection has been scheduled to review this and other events to determine if further NRC action is appropriate. This item is unresolved (50-219/88-23-01).

10.2 Augmented Offgas Door Open

During a tour of the facility, the inspector found a double equipment access door open in the augmented offgas building (AOG). The inspector discussed this with a contract supervisor and worker and was informed that they had obtained permission from the radwaste operations supervisor to open the door. The inspector concern was the potential for a ground level release from the AOG building. The AOG building operates at a slightly negative pressure, but the inspector was concerned for the potential for a release considering recent operational experience with the AOG building. This concern was discussed with radiological control (RADCON) management who agreed with the inspector's concern and felt that they should have been consulted on opening the doors. The licensee reviewed this and could not determine that anyone had given permission to the contractors to open the door. The licensee plans to exercise better control over contractor activities.

10.3 Disposal of Radioactive Material

On August 26, 1988, the inspector found wet trash from the reactor building spread in the sun to dry outside the radwaste shipping area, but inside the fenced in area of the radiological control area (RCA). In discussion with RADCON the inspector learned that the wet trash from cleaning a seawater side of a heat exchanger had not been frisked out of the RCA prior to drying it in the sun. RADCON stated that it was their policy to frisk out any trash before it is removed from the turbine building or any part of the RCA. RADCON management discussed this with the personnel involved, gathered the trash from the RCA yard and properly frisked it. The trash was found to be within acceptable limits for release outside the RCA. The inspector had no further concerns.

10.4 Radioactive Control Area Entry

During this period, company personnel were found to be using the reactor building 23' elevation as a passageway to obtain self-reading dosimetry (SRD) prior to entering the RCA. The reactor building comprises a portion of the RCA where general radiation levels are about 1-2 mrem/hr. The licensee had recently relocated the dosimetry issue facility and as a result company personnel were unaccustomed to the new location, but this does not provide justification for entering the RCA prior to SRD issue. The licensee promptly posted personnel, including a senior member of the management staff, to stop this unauthorized passage through the RCA and clearly marked the proper path to access the dosimetry issue facility. Further NRC review of this occurrence has been scheduled.

10.5 General

During entry to and exit from the RCA, the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. Posted extended Radiation Work Permits (RWPs) and survey status boards were reviewed to verify that they were current and accurate. The inspector observed activities in the RCA to verify that personnel complied with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area. No unacceptable conditions were identified.

11.0 Plant Operational Review

11.1 Reactor Start Up

Facility startup activities during the period August 9 through August 11, 1988, were reviewed by a region-based inspector. Plant startup activities on August 9 were delayed pending the completion of a safety evaluation (SE) for the damage done to the drywell during the work associated with the installation of a cathodic protection system. The SE was completed at approximately 1:00 p.m. and sent to Region I for review. Region I completed its review of the SE at approximately 3:00 p.m. The remaining holdup for plant startup was then the SE for operation with the d.c. motor associated with the rotary inverter which powers instrument panel No. 3 being inoperable. Part of the rotary inverter evaluation was the performance of several tests to verify power to the instrument panel would successfully swap to alternate power from a transformer should the a.c. power to the rotary inverter be lost. The inspector observed portions of this testing, both at the inverter and in the control room.

The testing was performed in accordance with an approved procedure, discussed prior to being performed and had compensatory measures established in the event unacceptable conditions developed. The initial testing was unsatisfactory and a temporary variation had to be initiated in order to achieve acceptable results. The licensee's actions in determining acceptability of operation with the d.c. motor of the rotary inverter inoperable were found to be acceptable.

Startup was commenced at 2:17 a.m. on August 10, 1988. Criticality was achieved at 3:47 a.m. The criticality occurred more than 1% delta K sooner than expected by the estimated critical position which had been calculated prior to startup. The reactor was made subcritical and a review of the potential reactivity anomaly was reviewed by the Onsite

Core Group, the Onsite Independent Review Group and by Systems Engineering in Parsippany. The error in the estimated critical position (ECP) was determined to have been due to the use of an incorrect reactivity bias in the calculation of the ECP.

Following the resolution of the ECP problem the reactor was again made critical at 5:02 p.m. on August 10, and the 1000 psi inspection started at 4:50 p.m. on August 11. Some additional difficulties were experienced during the startup. These included IRM problems, a condenser vacuum breaker problem, and Rod 22-03 position indication problem and subsequent inability to withdraw 22-03. The operators' actions in resolving these issues, as they occurred, were acceptable. The inspectors will review licensee long term corrective actions in a future inspection.

Control room observations were made to verify:

-- Proper manning,

-- Operator adherence to procedures,

-- Acceptable status of annunciators for the plant condition and operators' response to annunciators,

-- Adherence to technical specification requirements,

-- Shift turnovers,

-- Overall control of activities in progress,

-- And, control rod withdrawal in accordance with technical specification requirements for an inoperable rod worth minimizer.

No unacceptable conditions were identified.

11.2 Operational Events

The inspector reviewed details associated with key operational events that occurred during the report period. A summary of these inspection activities follows.

11.2.1 Hot Weather Operation

As a result of a regional request the inspectors reviewed the effects on plant operations which resulted from this summer's prolonged heat wave.

For a portion of the heat wave, July 11, 1988, to August 12, 1988, the plant was shut down and unaffected by the hot weather.

The most significant effects on plant operation resulted from high intake canal temperatures. High intake temperatures made it necessary to operate 3 vs. 2 turbine building closed cooling water heat exchangers and 2 vs. 1 turbine lube oil coolers for some period of time.

The high circulating water intake temperatures caused certain State Environmental Discharge Permit (EDP) limits to be reached on several occasions. There are EDP temperature limits placed on both the discharge canal temperature (97 degrees F) and on the circulating water discharge (106 degrees F). On three days these temperature limits were reached which either halted power increases or forced power reductions to be taken in order to preclude exceeding EDP temperature limits. On August 13, the power increase from the startup of August 10 was temporarily halted due to circulating water discharge temperature. During the day on August 14, power was reduced approximately 18% and on August 15, power was reduced by approximately 13%. The reductions were taken to keep temperatures within the limits of the EDP.

The discharge canal temperature did exceed its limit of 97 degrees on August 15 when a dilution pump tripped. Before the dilution pump was restarted temperature reached 97.9 degrees and remained above the limit for approximately 15 minutes. The licensee notified the state of New Jersey of this condition.

Under certain emergency load conditions these EDP limits can be increased, but these conditions were not exceeded this summer.

Inspectors reviewed the station Final Safety Analysis Report and noted that the design cooling water temperature for the containment spray/emergency service water heat exchangers is 85 degrees. During the summer canal temperature did exceed 85 degrees. The licensee is reviewing this condition for reportability.

Overall, no significant operational problems were experienced as a result of the high temperatures. The ability of the heat exchangers to perform their design function with injection temperature greater than 85 degrees is unresolved pending completion of licensee evaluation and inspector review (50-215/88-23-02).

11.2.2 Operational Events

As an result of the startup problems incurred with some equipment, the inspector reviewed the licensee's program to identify rework problems and implement corrective action. During the startup from 11-U-7, the inspector identified the following equipment that had been worked on by the licensee:

- Safety relief valve thermocouples on safety valves NR28M and NR28H.
- Intermediate range monitors 12 and 18.
- Hydraulic control accumulator 22-03.
- Recirculation pump "C" controller.
- Reactor feed pump "B" motor bearing.

The licensee identified these equipments and others as examples of rework. In addition the licensee held a critique of the 11-U-7 outage including rework problems, which the inspectors attended. The critique recommended invoking the rework procedure to determine root cause. The inspectors will review results of the licensee's root cause determinations.

The licensee has a Maintenance Construction and Facilities (MCF) procedure in place to identify rework and recurring maintenance. This procedure A000-ADM-7000.01, Control of Rework and Recurring Maintenance, has as its purpose to establish a process for identifying rework and recurring maintenance and taking steps to reduce it. This procedure specifies that when rework or recurring maintenance is identified it is documented on either a Rework Identification and Corrective Action Report or on a Recurring Maintenance Report.

Discussions with the licensee and a review of records shows that since the procedure was issued on March 1, 1987, six Rework and Corrective Actions Reports and one Recurring Maintenance Report have been prepared. Of these six reports only one has been completed to where the corrective action completed section has been signed off.

Additionally, the procedure requires an annual review of rework activities and the preparation of a report to the MCF Site Director addressing rework, trend, evaluation of rework as it impacts plant availability, etc. This annual review has never been performed.

A number of people having responsibilities associated with the Control of Rework and Recurring Maintenance Procedure indicated that in general the procedure was not being fully utilized and was not doing an adequate job.

The licensee indicated there are redundant methods which indirectly address rework, recurring maintenance, and corrective actions. These are LER's, the extensive use of critiques, and various computer sorts.

Recurring maintenance activities and the use of A000-ADM-7100.01 was audited by QA in October, 1987. This audit indicated that the procedure is not frequently implemented. At that time maintenance had initiated five Rework Reports and one Recurring Maintenance Report. The Audit Report concluded "MCF is cognizant of the problems with the implementation of this program and is taking steps to resolve the problems." This assessment still appears to be accurate.

During the exit meeting the licensee indicated that a Maintenance, Construction and Facilities self assessment had come to the same conclusions as the inspectors and stated that action items had been issued to correct identified deficiencies.

11.2.3 Emergency Service Water Pumps

During testing of the Containment Spray/Emergency Service Water (ESW) System II on August 16, 1988, ESW pump 52C had excessive seal leakage. The pump was declared inoperable. Subsequently, during inservice testing (IST) of ESW pump 52D, pump differential pressure was in the high "required action range". The licensee also declared this pump inoperable, placing the facility in a 7-day limiting conditions for operations.

Licensee review of the test data on ESW pump 52D indicated that the pump differential pressure obtained during the test was significantly displaced from the recorded pump performance curve. Because of this, the licensee performed a calibration check on the pump discharge gauge and the instrument sensing lines on the flow indicator were "back flushed" into the process pipe.

The IST on ESW pump 52D was performed again on August 18, 1988, with acceptable test results. Subsequently, the pump was declared operable. The licensee disassembled and inspected ESW pump 52C and concluded that the pump should be replaced. This was accomplished, and ESW pump 52C was returned to service on August 19, 1988. The inspector noted the ESW pump 52C had previously been replaced in 1984. The inspector will review ESW pump maintenance history and performance in a future inspection.

11.2.4 Hydraulic Control Units

Inspectors noted that three hydraulic control units were operated for a period of time greater than one hour with accumulator pressures below the low pressure alarm. This condition was annunciated in the control room and developed when the nitrogen charging hose malfunctioned. The licensee subsequently repaired the nitrogen charging hose and recharged the accumulators. The licensee will be reporting this event via the licensee event reporting system.

11.2.5 MSIV Surveillance Testing

While the licensee was concerned about the MSIV limit switch problem discussed in paragraph 9.0, the daily 5% MSIV closure test surveillance was not performed at the scheduled time. The test was subsequently performed after completion of electrical maintenance approximately 12 hours after the scheduled time. The licensee currently has no written definition of "daily" surveillance requirement. Operations has in the past interpreted "daily" as anytime within a 24-hour day. This potentially could allow dailies to be conducted almost 48 hours apart. In practice though this has not been the case and the licensee is timely in conducting daily surveillances. In the past a missed weekly surveillance led to a licensee effort to clarify periodic surveillance requirements. This had not been accomplished when this surveillance was performed late. Presently the licensee intends to specify in writing the length of periodic surveillance requirements.

11.2.6 Reactor High Pressure Scram Surveillance

The inspector reviewed the results of recent surveillances on RE03A, high pressure scram instrument and RE15's, isolation condenser initiation and recirculation pump trip on high pressure. One of four RE03A had drifted high and was found at 1070 psig while the technial specification limit is $\leq$1060 psig. Three of the four RE15's had drifted high out of specification. The licensee currently plans on replacing these pressure switches with an analog trip upgrade system in the 12R refueling outage. RE03A previously was the cause of concern due to microswitch contact resistance coupled with vibration problems (see Inspection Report 88-04). The inspector will continue to follow the performance of these pressure switches.

11.2.7 Acoustic Monitor

During this report period the acoustic monitor for NR28M and the thermocouples for NR28H and M were declared inoperable. The inspector verified that appropriate actions were taken in accordance with technical specifications by increasing the gain on adjacent acoustic monitors NR28J and N. NR28M acoustic was bypassed by the licensee to eliminate the constant alarm in the control room. The NR28M acoustic monitor may be indicating a minor steam leak associated with the safety relief valve. The licensee has not detected any other containment parameter increase that would be indicative of a steam leak. Prior to shutdown for the MSIV repair outage in July, 1988, the NR28A acoustic monitor had exhibited similar characteristics. Later inspection found minor damage to surrounding pipe insulation and steam cutting of the NR28A flange, which the licensee repaired prior to startup. The licensee continues to closely monitor the acoustic systems.

11.3 Control Room

Routine tours of the control room were conducted by the inspectors during which time the following documents were reviewed:

-- Control Room and Group Shift Supervisor's Logs;

-- Control Room and Shift Supervisor's Turnover Check Lists;

-- Reactor Building and Turbine Building Tour Sheets;

-- Equipment Control Logs;

-- Standing Orders; and,

-- Operational Memos and Directives.

11.4 Facility Tours

Routine tours of the facility were conducted by the inspectors to make an assessment of the equipment conditions, safety, and adherence to operating procedures and regulatory requirements. The following areas are among those inspected:

-- Turbine Building

-- Vital Switchgear Rooms

-- Cable Spreading Room

-- Diesel Generator Building

12.0 Monthly Surveillance Observations

On August 5, 1988, the inspector observed the complete performance of Surveillance Procedure 609.4.001, "Isolation Condenser Valve Operability and In Service Test". This surveillance tests the opening and closing times of isolation condenser isolation valves. The inspector verified the surveillance met technical specification requirements, the test results were within the acceptance criteria, the test instrumentation were within their calibrated periodicity, approval granted to conduct the test and review of surveillance by the Group Shift supervisor, surveillance prerequisites were completed and appropriate electrical safety precautions were taken. Further management review of the surveillance was not verified because the procedure as of September 16, 1988, was still in routing. The inspector witnessed Surveillance Procedure 609.4.001 for both the "A" and "B" isolation condensers on September 2, 1988. This surveillance was conducted to verify isolation condenser operability after entering the limiting conditions for operations discussed in paragraphs 1.0 and 2.0. No unacceptable conditions were identified.

13.0 Observation of Physical Security

13.1 On August 4, 1988, after cleaning and loading a firearm, a security guard inadvertently discharged the firearm. This event occurred in the lunch room of the main guardhouse, outside the site protected area. No personnel injuries occurred. The inspector discussed this event with regional security inspectors, including a review of the sequence of events. The inspector concluded that licensee actions were timely and effective in response to this event. No concerns were identified.

13.2 During daily tours, the inspectors verified that access controls were in accordance with the Security Plan, security posts were properly manned, protected area gates were locked or guarded and that isolation zones were free of obstructions. The inspectors examined vital area access points to verify that they were properly locked or guarded and that access control was in accordance with the security plan.

14.0 Backshift Inspection

NRC inspections of licensee activities on backshifts were conducted on the following dates: Saturday, August 6, 1988 and Friday, September 2, 1988.

15.0 Exit Interview

A summary of the results of the inspection activities performed during this report period were made at meetings with senior licensee management at the end of this inspection. The licensee stated that, of the subjects discussed at the exit interview, no proprietary information was included.

ATTACHMENT I

SUMMARY OF ACTIVITIES

VALVE V-14-6

DATE	ACTIVITY
July 13	Valve V-14-6 tagged in the "closed" position for maintenance activities. No "as found" position is recorded for tagouts.
July 22	Tagout cleared, V-14-6 returned to the "open" position.
July 31	Performed 665.5.003, Section 10: -- Step 10.2: Documented V-14-6 pretest position as "open". -- Step 10.5: Directed V-14-6 to be opened. Valve was not repositioned. -- Step 10.18: Directed valves to be returned to "pretest position". This would be "open" for V-14-6. Valve V-14-6 not repositioned during this test.
August 2	Performed 665.5.003, Section 10: -- Step 10.2: Documented V-14-6 pretest position as "open". -- Step 10.5: Directed V-14-6 to be opened. Valve was not repositioned. -- Step 10.18: Directed valves to be returned to "pretest position". This would be "open" for V-14-6. Valve V-14-6 was not repositioned during this test.
August 3	Performed 665.5.003, Section 7: -- Step 7.12: Documented the pretest position of V-14-6 as "open". -- Step 7.13: Closed V-14-6. -- Step 7.37: Opened V-14-6. -- Step 7.52: Closed V-14-6. -- Step 7.72: Directed valves to be returned to their as-found positions. This would be "open" for V-14-6.
August 4-5	Performed 665.5.003, Section 10: -- Step 10.2: Documented V-14-6 pretest position as "closed". -- Step 10.5: Directed V-14-6 to be opened. Valve repositioned to the open position. -- Step 10.18: Directed valves to be returned to pretest position. This would be "closed" as documented in Step 10.2.
September 2	Valve V-14-6 found "closed". Valve V-14-6 repositioned to "open".