U. S. REGULATORY COMMISSION
REGION I

Report No. 50-219/89-16

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 2, 1989, - July 29, 1989

Participating Inspectors: M. Banerjee, Resident Inspector
S. Chaudhary, Senior Reactor Engineer
E. Collins, Senior Resident Inspector
H. Gregg, Senior Reactor Engineer
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Approved By: J C Beall FOR 8/18/89
C. Cowgill, Chief Date
Reactor Projects Section 4B

Inspection Summary:
Inspection July 2 - July 29, 1989 (Report No. 50-219/89-16)

Areas Inspected: Inspection consisted of (234 hours) by resident and regional based inspectors. The areas inspected included observation and review of plant operational events (paragraph 2.0), corrective actions associated with the control of high radiation areas (paragraph 3.0), evaluation of plant operation with high canal water temperatures (paragraph 4.0), review of main transformer failures (paragraph 5.0), review of security response to vital area door problems (paragraph 6.0), surveillance observations (paragraph 7.0), observation of control rod drive pump motor installation (paragraph 8.0), evaluation of testable check valve leakage test acceptance criteria (paragraph 9.0), review of LER 89-15 (paragraph 10.0) and review of previously opened inspection findings (paragraph 11.0).

Results: Plant startup and operation on a temporary transformer were performed with only minor problems. Overall, the plant was operated in a safe manner. Problems continue to be experienced in the area of control of high radiation

areas. These problems are evidenced by nine events since August 1988. Most of these events involved the control of locked high radiation area doors. Corrective actions were either untimely or ineffective. Prompt action is warranted to gain control of this problem and to identify effective long-term corrective steps. A notice of violation is enclosed.

The technical evaluation associated with operation of the plant with canal temperatures above 85 degrees was not completed one-year after identification by NRC inspectors in July 1988. Neither plant technical specifications nor plant procedures reflect 85 degrees as an operational limit, even though it is a design basis number and is used in the analysis of the plant response to the design basis accident. Preliminary licensee evaluation, at the current reduced power levels, shows torus temperature response to be acceptable with canal temperatures up to 95 degrees. However, the licensee operated the plant at temperatures above 85 degrees without performing a written safety evaluation. A notice of violation is enclosed.

Two main transformer failures were apparently related and were brought on by a combination of previous equipment deficiencies and maintenance performed during the previous outage. A security violation resulted in a vital door without monitoring. This violation will not be cited in a Notice of Violation because it was licensee identified and promptly corrected. Twelve previously opened inspection findings were closed.

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DETAILS

1.0 List of People Contacted

E. Fitzpatrick, Director Oyster Creek
G. Busch, Licensing Mgr.
K. Mulligan, Plant Operations
P. Crosby, Operations Engineer Supervisory
P. Cervenka, Operations Engineering
D. Jones, Electrical Engineer
D. Ranft, Elect/I&C/OPS
J. Frank, Plant Analysis
R. Farrell, Rad Engineer
R. Brown, Plant Operations Mgr.
R. Ewart, Security
K. Wolf, Rad Engineering Mgr.
P. Smith, Technical Functions
J. Lagatto, Technical Functions
J. Rogers, Licensing
A. Hawley, Operations Engineer
A. Rone, Director Plant Engineering
R. Fenti, QA Mod/OPS Mgr.
D. Mac Farlane, QA Site Audits Mgr.
R. Markowski, Quality Assurance
J. Solakiewicz, OPS QA Mgr.
P. Scallon, Radwaste Operations Mgr.

2.0 Review of Plant Operations (71707, 93702)

2.1 Review of Operational Events

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

Plant Trip

On July 11, a fault in the M1B main transformer initiated a generator/turbine trip and a reactor scram. At the time of the fault, the plant was operating on one main transformer because the M1A main transformer had similarly failed on June 25 (Inspection Report 50-219/89-14). The plant was operating at 57 percent of rated thermal power.

The fault in the M1B main transformer caused more severe damage than that by the M1A main transformer in June. The M1B main transformer had faults in all three phases and exhibited significant external damage. The rapid increase in temperature and pressure caused by the faults resulted in the sides of the transformer housing bulging outward. The seam on one edge of the transformer housing cracked.

Oil was sprayed through the transformer relief valve and housing crack. All three lightening arrestors were broken. The fire protection system actuated; however, no fire occurred.

The transient on the plant was less severe than the previous trip because the plant was operating at 57 percent power versus 100 percent. The maximum pressure attained during this transient was 1036 psig. As a result of the smaller pressure transient, the isolation condensers did not initiate, the electromatic relief valves did not actuate and the recirculation pumps did not trip. These systems did initiate during the June 25 trip. The plant responded normally and as designed. Two control rods, however, were at position 02 versus the fully inserted position after the scram. The inspector noted that the licensee satisfactorily completed testing on these two control rods prior to startup.

The inspector attended the licensee's Post Trip Review Group (PTRG) meeting. The overall conclusion from the PTRG was that the trip was very similar to that which occurred on June 25. The plant had responded as expected and the operators' response was very good. The PTRG recommended that certain actions be completed prior to startup. These actions included: (1) determining the potential adverse effects on the plant's and JCP&L's electrical systems, (2) evaluating the possibility of a common mode failure mechanism which may affect the replacement transformer, auxiliary or startup transformers or the main generator, (3) determining if any actions needed to be taken prior to returning the generator to service, and (4) performing surveillance 617.4.010, Troubleshooting Control Rod Drives that Settle at Position 02 Following a Reactor Scram, for control rods 18-23 and 30-19. These actions were completed prior to startup. The inspector had no questions about the plant's and operators' responses to the transient.

Plant Startup

The licensee performed a plant startup on July 17. The inspector observed portions of the plant startup including the rod withdrawal sequence, the heatup of the plant and the preshift brief. The inspector noted that twenty four hour coverage was provided by plant management during the startup.

One problem encountered during startup was a blown fuse in the reactor manual control system (RMCS). This failure caused several rod block alarms and resulted in the inability to withdraw control rods. The licensee replaced the fuse; however, upon post maintenance testing, the fuse blew again. After further troubleshooting, the licensee determined that faulty thyristers in relay 4K3 were causing the fuse to blow. The thyristers were replaced and no further problems in the RMCS were encountered. The inspector had no questions on the plant startup and heatup.

Reactor Building to Torus Vacuum Breaker Differential Pressure Switches

During performance of a monthly surveillance test on 7/25/89 the reactor building to torus vacuum breaker differential pressure (dp) switch 66A failed to reset. Following the requirements of the plant technical specification 3.5.4.C, the dp switch 66A was declared inoperable at 11:00 p.m. and a controlled shutdown initiated. The switch was replaced and declared operable at 6:05 a.m. on the following morning and the shutdown was halted. The reactor was then brought back to the administrative power limit corresponding to 425 MWe.

The inspector reviewed the switch failure and licensee's immediate corrective action. The inspector concluded that the licensee took the appropriate action as required by the plant technical specifications. This dp switch has a history of reset anomalies. IE Bulletin 86-02 identified problems experienced at LaSalle and Oyster Creek with model 102 and 103 static ±O' ring (SOR) dp switches. The dp switches 66A and B, and core spray booster pump dp switches RV-40 A, B, C and D are addressed by this IE Bulletin. RV 40 D switch had failed to actuate during a surveillance in January 1989. With the information provided in the IE Bulletin and recent switch failures, the inspector was concerned about the reliability of these SOR pressure switches. The licensee is expediting the submittal of a follow-up response to the IE Bulletin and intends to implement a plant modification which uses switches of a different manufacturer.

2.2 Control Room Observations

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;

-- Technical Specification Log;

-- 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.

2.3 Facility Tours

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

-- Turbine Building

-- Vital Switchgear Rooms

-- Cable Spreading Room

-- Diesel Generator Building

-- Reactor Building

The following additional items were observed or verified:

a. Fire Protection:

-- Randomly selected fire extinguishers were accessible and inspected on schedule.

-- Fire doors were unobstructed and in their proper position.

-- Ignition sources and combustible materials were controlled in accordance with the licensee's approved procedures.

-- Appropriate fire watches or fire patrols were stationed when equipment was out of service.

b. Equipment Control:

-- Jumper and equipment mark-ups did not conflict with technical specification requirements.

-- Conditions requiring the use of jumpers received the prompt attention of the licensee.

-- Administrative controls for the use of jumpers and equipment mark-ups were properly implemented.

c. Vital Instrumentation:

-- Selected instruments appeared functional and demonstrated parameters within Technical Specification Limiting Conditions for Operation.

d. Housekeeping:

-- Plant housekeeping and cleanliness were in accordance with approved licensee programs.

No unacceptable conditions were identified.

2.4 Summary

Overall, plant operations were conducted in accordance with facility procedures. The operator's response to the plant trip was very good. The startup was conducted in an orderly fashion with only minor equipment problems. No unacceptable conditions were identified.

3.0 Control of High Radiation Areas (71707, 92701)

Inspection Report 50-219/88-23 documented an event which occurred on August 30, 1988, whereby a door to a high radiation area was left unlocked and unattended. Immediate corrective actions for this event were taken; however, a critique had not yet been completed at the time of the inspection. The incident was left unresolved (Unresolved Item 50-219/88-23-01) pending the results of a future review of this event and other similar events.

During this inspection period, a review was conducted on events since August 1988 which involved uncontrolled/unguarded high radiation areas. The inspector reviewed the circumstances surrounding these events as documented in the licensee's radiological incident reports (RIRs) and critiques, and evaluated the effectiveness of the corrective actions.

Description of Events

Nine RIRs were generated by the licensee since August 30, 1988. During a period of approximately ten months, seven incidents occurred in which doors to high radiation areas were left unlocked and unattended, and two incidents occurred in which high radiation areas were left unguarded.

Of the nine RIRs, the critiques associated with seven RIRs were available for the inspector to review. One RIR determined that a critique was not required because the cause of the incident was an equipment failure. The critique associated with another RIR was not reviewed because, at the time of the inspector's review, the licensee was not able to provide the inspector with the documentation of the critique because the responsible engineer was on vacation.

The inspector noted that the causes for most of the events involved personnel errors and were recurrent in nature. For example, RIR 88-023 documented an event in which a locked high radiation door was blocked open 70 degrees. The licensee's investigation into the event failed to conclusively determine a root cause; however, one possible contributing cause was determined to be failure to physically challenge the door to

ensure it was locked. The corrective action to address the problem of personnel failing of physically challenge the door was to revise procedure 9300-ADM-4110.06, to include a positive listing of responsibilities of the person who signs out the key. This procedure change has just recently been implemented. In the interim, events had continued to occur in which a contributing cause was the failure to adequately challenge the door. These events were documented in RIRs 89-003, 89-028 and 89-031. In RIRs 89-003 and 89-028, the corrective actions included instructing personnel involved in the need to physically check the door, and reiteration to personnel of the requirements of procedure 9300-ADM-4110.06. In RIR 89-031, the corrective action again stated the need to evaluate whether or not procedure 9300-ADM-4110.06 should be rewritten to provide instructions for physical challenges. Additionally, the licensee reemphasized to site personnel the significance of the event and the proper methods and practices to ensure that doors are locked.

The inspector noted that some of the RIRs were not completed in a timely manner. Procedure 9300-ADM-1201.01, Investigation of Radiological Incidents, states the RIR should be completed by the responsible manager within seven days of the date of receipt. RIR 89-028, which was issued on April 28, 1989, documented an event in which the door to the New Rad Waste fill aisle was left opened. The RIR was not completed until three months later. RIR 89-008 was issued as a result of an event in which a high radiation area was left unguarded. RIR 89-008 was not completed for over a month after the event. RIR 89-031 was issued as a result of an event in which the Regeneration Tank door was left unlocked and unattended. Though the critique was completed within five days of receipt of the of the RIR, the individual responsible for the critique noted that five days had already elapsed between the time the event occurred and the RIR was received. Because of this elapsed time, the recollection of parties involved was less clear and some discussion of the incident among various parties had already taken place. The lack of timeliness in the above incidences impacted the effectiveness of the critiques and RIRs.

Some RIRs and the associated critiques were shallow. The root cause identified in these RIRs was personnel error, and the corrective actions were limited to personnel counselling and information to site personnel. No long term effective corrective actions were identified in these RIRs.

Summary

In a period of approximately ten months, nine RIRs were generated to document events involving uncontrolled high radiation areas. Actions to preclude these occurrences have had minimal effect as evidenced by continued incidents of similar causes. In some cases, the completion of the RIR and implementation of corrective actions have not been timely. In other cases, the RIRs and associated critiques were shallow and long term corrective actions were not identified.

NRC requirements, as specified in 10 CFR50, Appendix B, and the licensee's requirements, as specified in their Operational Quality Assurance program, require that measures be established to promptly identify and correct conditions adverse to quality. The cause of significant conditions adverse to quality shall be determined and appropriate action taken to prevent recurrence. In the events involving the control of high radiation areas, steps to prevent recurrence have not been adequate and have not reduced the recurrence of these events. This is a violation. (50-219/89-16-01)

4.0 Canal Water Temperature (71707,92701)

Inspection Report 50-219/88-23 describes an event in which the intake canal water temperature exceeded 85 degrees F in July 1988. The Oyster Creek Final Safety Analysis Report describes the containment spray/emergency service water (ESW) heat exchanger to have a total heat removal capacity of 50 million BTU/hr when supplied with 130 degrees F water from the suppression pool and 85 degrees F sea water from the ESW system. Pending an evaluation for acceptability and reportability of plant operation with canal water temperature above 85 degrees, this item was left unresolved (50-219/88-23-02).

In July 1989, a formal safety evaluation had not been finalized and thus was not available for NRC review. Preliminary evaluation with 90 degrees intake canal water temperature resulted in about a 1.5 degree increase in peak torus water temperature. The impact of the increase in peak torus water temperature on Core Spray pump net positive suction head (NPSH) was not formally evaluated. The completion of this evaluation was of low priority due to low perceived safety significance.

On July 28, another preliminary evaluation of plant operation with canal temperature above 85 degrees was performed. This analysis used 60% reactor power and 95 degrees canal temperature. Results showed peak torus temperature to be about 142 degrees F. This peak is below the NPSH requirement of 149.6 degrees F. for the most limiting core spray pump. Further analysis is required to determine acceptability at 100% power. These analysis will be documented in a written safety evaluation. Based on these results, plant operation in the current configuration (about 70% power) is acceptable.

The following conclusions were reached by the inspector:

- Failure to complete the safety evaluation in a timely manner resulted in the plant being operated in an unanalyzed condition and potentially outside the design basis as the ESW system is the ultimate heat sink for core decay heat during a design basis LOCA.

- The licensee failed to report this event to the NRC.

- The licensee's low priority to complete the analysis resulted in a repetition of the above event.

- The margin for NPSH to the limiting Core Spray pump is very small, thus, any increase in the heat sink temperature above that used in the analysis is potentially safety significant and warrants prompt evaluation.

- The torus temperature response curves in the FSAR-update represent two pump operation in one Containment Spray loop. The current system design allows only one pump to operate per loop.

- The licensee's procedures require performing a safety evaluation before performing plant modifications (hardware changes), procedure changes, or new tests or experiments. However, the licensee's procedures do not require performing a prompt safety evaluation to determine acceptability of plant operation when changes to the assumed parameters of the accident analysis occur.

During July 1988 and July 1989, the plant was operated with elevated canal temperatures which resulted in the plant being in an unanalyzed condition. 10 CFR Appendix B, Criterion XVI requires that measures be established to assure that conditions adverse to quality are promptly identified and corrected. After being identified by the NRC, the licensee failed to take prompt corrective action in that, even after one year, an analysis was not completed to determine the safety of the plant while operating with ESW temperature above 85 degrees F. This is a violation (50-219/89-16-02).

5.0 Transformer Failures (71707)

5.1 Review of Licensee Response to Transformer M13 Failure

Prior to plant operations on the replacement transformer, Region I management and resident inspectors met with the licensee on July 13 to discuss their evaluation of transformer M1B failure. Transformer M1A had failed on 6/25/89 (Inspection Report 50-219/89-14). The scope and status of the licensee's review was presented.

Three areas of focus were identified by the licensee to be reviewed for potential problems. These were: 1) the transformers themselves, 2) equipment from the transformers out into the electrical distribution system, and 3) equipment from the transformers into the plant.

In regard to the transformers themselves, the root cause of the failure had not been determined, but it was thought that the fault probably originated internal to the transformers and was related to the maintenance performed during 12R outage.

In regard to plant equipment, it was concluded that the site auxiliary transformer was not adversely affected. No work had been performed on the startup transformers during the 12R outage, and they

were not exposed to the faults in M1A or M1B. It was also concluded that the station generator was not negatively impacted. Subsequent internal inspection of the generator confirmed there was no loosening of the generator stator.

In regard to the grid, an independent consultant reviewed the impact of these transformer failures and identified no problems.

No unacceptable conditions were identified.

5.2 Cause of Failure

The licensee's review of the failed transformers identified that during the 12R outage the cooling oil distribution boxes were discovered split and had been repaired. Also, a core sample from M1B showed deteriorated insulation. It was concluded that long term operation of the transformers with inappropriate cooling oil distribution probably resulted in localized overheating of the coils. This overheating led to accelerated degradation and embrittlement of winding insulation. This effect, combined with the coil movement during 12R outage and vibration from operation caused the transformer failures. The licensee's efforts are continuing with regard to the transformer failures.

6.0 Security Event (71707, 93702)

On July 11, the licensee failed to take adequate compensatory actions for a failed alarm on a door to an unoccupied vital area. The failure to take adequate compensatory actions was not discovered by the licensee until five hours later. The inspector reviewed the circumstances surrounding and the licensee's conclusions on this event.

Although security personnel immediately responded to the failed alarm, full compensatory action for the circumstances was not accomplished for over five hours. When discovered by the licensee appropriate actions to ensure that no unauthorized entry occurred were taken and the event was properly reported to the NRC per 10 CFR 73.71.

The licensee's review determined the causes of this event to be (1) weak communication among the security personnel, (2) insufficient followup by the on-duty Shift Commander, and (3) knowledge deficiencies by some individuals on the requirements for vital area protection and the operation of security equipment. The licensee initiated retraining of certain individuals, emphasized the need for proper communications and upgraded the requirements for security personnel training. The inspector questioned the licensee on the proper use of procedures. The licensee believed responding to these alarms is a frequent evolution with which security personnel are familiar. The requirements for unoccupied vital areas should be very basic knowledge to security personnel. The inspector had no further questions.

Failure to provide adequate compensatory action for inoperable intrusion detection system equipment for a vital barrier door is a violation. This violation is not being cited because the criteria specified in Section V.A of the Enforcement Policy were satisfied. (NV89-16-03)

7.0 Surveillance Observations (61726)

7.1 Generator Load Reject

The inspector observed portions of the turbine generator load rejection scram test. The surveillance procedure was reviewed for conformance with the technical specifications and proper approval for test performance. The test instrumentation was verified to be properly calibrated. The technicians performing the surveillance were knowledgeable about the test procedure, system being affected and expected results. The test results were within acceptance criteria.

The inspector reviewed the completed test results and historical results from previous tests. It appeared that some pressure switches (Barksdale model B2T-M12SS) have experienced substantial setpoint drift mostly in the conservative direction. The licensee indicated the use of this type of Barksdale pressure switches is being phased out. The inspector had no further questions regarding pressure switch reliability.

7.2 Containment Spray and ESW Pump Operability and Inservice Test

The licensee conducted surveillance procedure 607.4.005, Containment Spray and Emergency Water Service Water Pump System 2 Operability and Inservice Test, on July 17. This surveillance verifies the operability of the pumps and selected valves in the Containment Spray and Emergency Service Water System.

The inspector observed portions of the surveillance. The operation of the pumps and valves were observed both locally and in the control room. Instrumentation readings were verified with those recorded on the data sheet. The data results were verified to be within the acceptance criteria of the surveillance. Conditions of the plant were verified to ensure that technical specifications were satisfied. The inspector had no questions on the performance of the surveillance.

8.0 Maintenance Observations (62703)

On July 2, the B control rod drive (CRD) pump motor failed. The licensee determined the failure was at the motor leads, which became virtually detached from the motor winding. This failure was attributed to poor workmanship of the vendor, G.E., who repaired the motor leads during January 1988 subsequent to a previous failure in December 1987.

The immediate corrective action was to replace the failed motor with a refurbished motor. The refurbished motor was repaired by G.E. subsequent to its failure in March 1989. This failure was attributed to a loose deflector plate. The deflector plate became loose and settled on the motor winding, thus shorting the motor.

The July 2 motor failure was documented in a deviation report which has not been closed out as of the end of the inspection period. The inspector questioned the licensee about the possibility of other safety related motors having loose deflector plates or degraded leads. The licensee considers the deflector plate failure to be an isolated case and is evaluating the cause of the degraded leads.

The inspector observed portions of the installation of CRD pump motor. Necessary approvals were obtained prior to initiation of the work, the equipment tagout was appropriate, the work sequence was according to the approved procedure, and quality control hold points were appropriately established for motor installation.

It was observed that this work was performed on a general Radiation Work Permit (RWP). A review of the job was performed by radiological controls personnel to determine if a job specific RWP was required. Based on this review, a determination was made that no job specific RWP was required. The inspector had no other questions related to the motor installation.

9.0 Core Spray Testable Check Valve Leak Test (61726, 71707)

During an inspector's review of procedure 610.4.008, Core Spray Testable Check Valve Leakage and In-Service Test, the consistency between the procedure's acceptance criteria and the technical specification requirement was questioned. Technical specifications indicated that the acceptance criteria for valve leakage was five gallons per minute (gpm). The inspectors interpreted the five gpm limit as corresponding to leakage at normal operating pressure (approximately 1020 psig). The surveillance, however, is performed prior to plant pressure reaching 600 psig. The measured leakage at the lower test pressure is compared to the technical specification leakage limit. The measured leakage is not pressure adjusted prior to comparing it to the acceptance criteria.

The licensee stated that the leakage requirement for the core spray testable check valves was written by the NRC and incorporated into technical specification via an order for modification of license issued in 1981. The licensee further stated that the literal reading of the technical specification indicated no requirement to perform pressure adjustments to the measured leakage; and, therefore such adjustments were not considered.

The inspectors pointed out that when the order for modification was issued to Oyster Creek, the technical evaluation report performed by the Franklin Research Center was enclosed as an attachment. The report states when leakage tests are made using pressures less than function maximum pressure

differential (i.e., normal operating pressure), the observed leakage shall be adjusted to function maximum pressure differential value. The report further states that the adjustment shall be calculated assuming leakage to be proportional to the pressure differential to the one-half power. Although the technical specifications do not delineate the requirement to pressure adjust or specify that the five gpm leakage criterion is applicable to function maximum pressure differential pressure, the intent as evidenced from the attached technical evaluation report was to perform pressure adjustments.

The licensee is making procedural changes to the surveillance to incorporate the pressure adjustment. The inspectors noted that previously measured leakage rates were well within the acceptance criteria even after the pressure adjustments were made to the observed leakage. The inspector concluded that although the technical specifications did not specify the requirements for pressure adjustments, the licensee conservatively decided to change their procedures once the original intent was understood. The inspectors have no further questions concerning the surveillance acceptance criteria.

10.0 Licensee Event Report (92720)

LER 89-15 described the main generator over excitation event on May 18, 1989, which resulted in a generator trip, reactor scram, but did not automatically transfer power to the startup transformers. This event and licensee's corrective action were reviewed in Inspection Report 50-219/89-12. The licensee committed, in a phone conversation with NRC Region I, to evaluate the need for modifying the plant such that the Start Up transformers would automatically energize the 4160 volt buses following an over-excitation trip, in addition to improving administrative controls and communication during maintenance and surveillance activities.

The Oyster Creek Facility Description and Safety Analysis Report (FDSAR) Section VIII-2-1, states "upon loss of the station generator during normal operation, the power requirements are automatically transferred to the startup transformers ". However, during the event, when the station generator was lost due to operator error, automatic transfer to the startup transformers did not occur. This resulted in a power loss to the 4160 V buses, a loss of 1A and 1B reactor feed pumps, and an automatic initiation of the Emergency Diesel Generators. The inspector could not establish, from this sentence in the FDSAR, the existence of an original licensee commitment to require the over-excitation trip to automatically transfer site loads to the start-up transformers.

In the LER, the licensee did not state the commitment to evaluate the need for modifying the plant design. The inspector questioned the licensee regarding the status and validity of this commitment. The licensee restated their commitment to perform this evaluation and is currently implementing the scoping effort into the budget.

11.0 Previously Open Inspection Findings (92701, 92702, 92703, 25027)

(Closed) 10 CFR 21 Report 86-88-01. Conval ball stop check valve defect preventing proper closure.

The licensee's letter of 7/26/86 notified the NRC of a defect which prevented the proper closure of the valve due to the ball lodging inside the spring. The inspector determined that 50 of these valves were purchased as substitutes for control rod drive (CRD) system valves V-106. The vendor subsequently designed a modification which added a spring guide part at the ball/spring interface to prevent the ball from entering the spring.

The inspector verified that the licensee's Plant Engineering and Technical Function Departments reviewed and accepted the modification as documented in the Material Nonconformance Report (MNCR 86-0255). The inspector also verified that all 50 valves were modified prior to installation in the CRD system. The inspector noted that the licensee was the sole purchaser of this valve. This item is closed.

(Closed) Unresolved Item 87-04-03. Damaged Core Spray System Hydraulic Snubbers.

This item was opened as a result of several unanswered questions pertaining to damaged snubbers NZ-2-S6 and NZ-2-S10. Snubber NZ-2-S6 was found with a bent threaded rod and a 1/8" base plate gap. Snubber NZ-2-S10 was found with a bent rod, a partially displaced spherical bushing, a loose turnbuckle jam nut and a loose sleeve type anchor bolt. The unanswered questions included: (1) the cause of damage; (2) means to prevent spherical bushing displacement; (3) testing for jam nut tightness; and (4) resolution of base plate gaps and loose anchor bolts.

The inspector reviewed the licensee's response to each question. Through testing of the snubbers and evaluation of video tapes of snubbers during system testing, the licensee concluded that the snubbers were not damaged through system operations but were damaged by personnel conducting maintenance in the area. The licensee revised both the hydraulic and mechanical snubber inspection procedures (675.1.001, Rev. 16 and A100-GMM-3921.52, Rev. 1) to limit the clearance of the paddle and clevis space. This limitation would prevent spherical bushing displacement. Quality Control (QC) and Maintenance, Facility and Construction (MC&F) departments took appropriate action to specify the adequate testing for jam nut tightness. The inspector verified that the bolts in tension had a 5.4 factor of safety and that the plate bending stress was within allowable limits as documented in Material Non Conformance Report (MNCR) 86-999 and Technical Function's Calculation C-1302-212-5320-021. The inspector also noted in MNCR 86-968 that the 1/8" base plate gap at snubber NZ-2-S6 was shimmed. This item is closed.

(Closed) Violation 87-07-01. Failure to Show Piping Modification on Drawing.

Two removable blind spectacle flanges, Y-1-57 and Y-1-58, were installed to eliminate the need for several isolation valves. One of the drawings depicting this piping, Dwg. GE 237E726 Revision 39, did not reflect the modification.

The inspector reviewed the licensee's response of 5/14/87 and verified that the described corrective actions were performed. Drafting standard DS-002 Rev. 2 was revised to require construction drawings to note all other affected drawings. The inspector also verified that drawing GE 237E726, Revision 45, was updated to include the spectacle flanges. This item is closed.

(Closed) Unresolved Item 87-08-02. Review of licensee's explanation of corrective actions taken for two system core spray snubbers erroneously deleted from the snubber list.

The inspector reviewed Licensee Event Report (LER) 87-017, which pertained to this item. The LER defined the omission as personnel error. The licensee's review of the safety significance of the issue was based on a worst case analysis with both snubbers considered inoperable. The review determined core spray system operability would not be affected. The inspector verified that the licensee's current procedure A100-GMM-3921.52, "Removal, Inspection and Installation of Mechanical Snubbers," and the piping isometric drawings have been revised to include the previously omitted snubbers. This item is closed.

(Closed) Unresolved Item 87-08-03. Resolution of Damaged Supports on Core Spray System and Full Flow Test Lines.

The inspector reviewed the licensee's Safety Evaluation SE 212-004 and verified that the unresolved item concerns were adequately addressed. The evaluation which considered seismic operability with degraded supports, determined that the IE Bulletin 79-02/14 calculations would still be valid and that the highest core spray piping stress is less than the allowable stress. Fatigue calculations were performed on core spray system 2, the bounding system, because it had more movement and support damage. The computer code model was backfitted with the 3" piping displacement as determined from piping scrape marks. The results demonstrated there was no significant fatigue reduction. Interferences that could restrict piping movement were conservatively modeled as new restraints, and the computer code was rerun to assure the conditions were bounded. The licensee's evaluations were appropriate. This item is closed.

(Closed) NRC Bulletin BU-87-02. Fastener Testing to Determine Material Conformance.

This bulletin required the licensee (1) to review its receipt inspection requirements and internal controls in fasteners and (2) independently determine, through testing, whether fasteners in stores at their facilities met required mechanical and chemical specification requirements.

The licensee submitted responses to the bulletin on 2/26/88. The 2/26/88 submittal addressed each action required by the bulletin. Additional information, which was requested in the supplements, was submitted by the licensee on 7/25/88.

The inspector evaluated the licensee's responses and determined that each of the bulletin requirements was appropriately addressed. The inspector noted that of the 40 fasteners tested (20 safety related and 20 non-safety related), five were out of specification. Of the five fasteners only one was a safety related item.

The inspector reviewed the Material Non Conformance Reports, and the licensee's evaluation and disposition of each of the five out of specification fasteners. The one safety related fastener (OC-002) had higher than allowable hardness. Of the 250 OC-002 fasteners purchased, 50 were used in a non-safety related application and were evaluated to be acceptable. The remaining 200 were scrapped. The four non-safety related fasteners were evaluated as follows: (1) fastener OC-022 was minimally out of specification for carbon content and was evaluated as acceptable because the mechanical properties were met; (2) fastener OC-021 which had high hardness was evaluated to be acceptable where used, and the remaining stock was scrapped; (3) fastener OC-023 which also had high hardness was evaluated to be acceptable for use; and (4) fastener OC-038 which had low hardness was evaluated as acceptable where used, and the remaining stock was scrapped.

The licensee's response to item 6 of the bulletin stated it had a program to assure quality of fasteners since 1986. The program verified the sample testing of raw materials and simple fabricated parts. The inspector noted that the licensee had verified the sample testing of 327 items since late 1985. Of these items 164 were fasteners. This item is closed.

(Closed) Unresolved Item 86-24-03. This item is related to the licensee's seismic analysis of piping. The analysis did not combine closely spaced modes as recommended in Reg. Guide 1.92, and the piping analysis indicated pipe stresses higher than allowable by governing code.

The above analysis which showed overstress condition was performed manually by span-table techniques. The licensee has reanalyzed the piping using dynamic analysis by computer, applying simultaneously two horizontal and one vertical seismic accelerations, which combines closely spaced modes as recommended by Reg. Guide 1.92. The above approach is conservative and much more rigorous than the original analysis. This item is closed.

(Closed) Unresolved Item 86-38-05. This item is related to the drywell thinning problems. The licensee has implemented a long range monitoring program and resolution of this problem. This problem is being tracked by several other open items by NRC. Therefore, to consolidate the tracking as one item this item is closed. The item tracking the above problem is 89-01-01.

(Closed) Violation 88-15-01. This item pertains to the licensee's acceptance of overstressed piping. A time-history analysis of the system indicated approximately 50% reduction in the calculated stresses compared to the analysis documented in MPR-999, Rev. 1. The reanalysis confirmed that there was no safety concern and the design margin was maintained. This item is closed.

(Closed) Unresolved Item 88-81-01. This item pertained to discrepant conditions of several pipe supports identified by the NRC. The licensee's resolution of the above concerns was reviewed and evaluated by the NRC, and were documented in the Inspection Report 50-219/89-01, paragraph 5.0. Based on the above review, this item is closed.

(Open) Unresolved Item 86-30-01. This item was reviewed by the NRC in Inspection Report 50-219/87-07 and was left open pending the licensee's actions in regard to final engineering evaluation and implementation of the crack monitoring program proposed by the licensee.

The licensee informed the inspector that a monitoring program has been implemented by installation of optical monitoring devices, and a number of these monitors have been read in the past year. However, the licensee's engineers feel that sufficient data over a long period of time has not been accumulated to determine the validity of observation and a meaningful technical analysis. The licensee is currently in the process of formalizing the monitoring program for inclusion in the plant ISI program for regular observation and data acquisition. The item remains open pending implementation of a formalized ISI monitoring program by the licensee.

(Open) Unresolved Item 89-01-01. This item pertains to the problem of drywell thinning. The licensee is continuing to monitor and evaluate the progress of the corrective measures and engineering evaluation. This item remains open pending the resolution of the problem and review by the NRC of the actions by the licensee in this regard.

(Closed) Unresolved Item 88-23-01. This item is addressed in paragraph 3.0 of this inspection report. This item is closed based upon issuance of violation 50-219/89-16-01.

(Closed Unresolved Item 88-23-02. This item is addressed in paragraph 4.0 of this inspection report. This item is closed based upon issuance of violation 50-219/89-16-02.

12.0 Exit Interview (30703)

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.