U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	92-16
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License No.	DPR-16
Licensee:	GPU Nuclear Corporation 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Inspection Period:	July 19, 1992 - August 25, 1992
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Inspection Summary: This inspection report documents the safety inspections conducted during day shift and backshift hours of station activities including: plant operations; radiological controls, maintenance and surveillance; engineering and technical support; emergency preparedness; security; and safety assessment/quality verification.

Results: Overall, GPUN operated the facility in a safe manner. Two reactor scrams occurred during this inspection period due to equipment failures.

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EXECUTIVE SUMMARY

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Plant Operations

Operators responded appropriately to the scram caused by the failure of the steam flow density compensation circuit in the feedwater control system. Operators also responded appropriately to the scram due to the failure of the feedback link for the internal bypass of the number 2 stop valve in the turbine control system. Each of the scrams was the result of equipment failure. Followup of the equipment operator tour and logkeeping deficiencies noted that the licensee has been aggressive in implementing corrective actions to prevent or quickly detect recurrence. Licensee identification and response to a concern on remote shutdown capability in the event of a fire in the control room were good.

Maintenance/Surveillance

Efforts to return electromatic relief valve acoustic monitor to service within the 48 hour technical specification time limit were well controlled, coordinated, and conducted. A poor worker practice was observed in that the workers used small diameter scram discharge instrument volume piping as a step while performing main steam line high flow sensor tests and calibrations.

Engineering and Technical Support

Review of the safety evaluation process by the NRR Project Manager for Oyster Creek determined the licensee's program remains adequate. No instances of unreviewed safety questions were identified in the evaluations reviewed by the Project Manager.

Emergency Preparedness

Observation of the licensee's quarterly emergency exercise found that the licensee's critique was useful in identifying performance areas for improvement.

Safety Assessment and Quality Verification

GPUN's management observation team effort in response to the diagnostic evaluation team (DET) of 1990 has not been aggressive. The focus has been primarily on radiological and industrial safety practices. More participation from managers who can provide informed assessment of work performance techniques is needed.

<u>DETAILS</u>

1.0 OPERATIONS (71707,93702,TI 2515/115)

1.1 Operations Summary

The unit was ope...ted safely throughout the inspection period. The unit started the inspection period at 100%. On July 20, 1992, reactor power was decreased to 94% to allow maintenance to be performed on the B recirculation pump motor-generator (MG) set. Power was returned to 100% on July 21. While testing the electromatic relief valve (EMRV) acoustic monitors at 8:35 p.m., on July 22, EMRV acoustic monitor NR108C was declared inoperable. The licensee entered a 48 hour technical specification shutdown limiting condition for operation (TS LCO) action statement (TS 3.13.A.3). The acoustic monitor was replaced with an existing spare channel and was returned to service at 7:50 a.m. on July 23, 1992.

On July 29, 1992, at 11:20 a.m., the #1 traversing incore probe (TIP) stuck outside the TIP shield and the TIP machine was declared inoperable. The licensee entered a 48 hour TS LCO action statement (TS 3.5.A.3). Instrument and control (I&C) technicians manually hand cranked the #1 TIP into its shield and the action statement was exited at 1:27 p.m. on July 29, 1992.

On July 31, 1992, the 51C system 2 containment spray pump breaker long time relay tripped causing the breaker to trip. This relay provides protection for excessive current being drawn during pump operation. TS LCO action statement 3.4.C.3 was entered allowing the licensee seven days to correct the condition. Electricians performed meggar and bridge tests of the pump motor and tested the motor breaker. No deficiencies were found with the motor. The failed long time relay was replaced and the breaker retested. Containment spray system 2 was retested and returned to an operable status at 11:55 p.m. on July 31, 1992.

The licensee identified a concern with the comparison of the manual heat balance and the computer generated heat balance on August 12, 1992. The manual heat balance was about 12 MWth higher than the computer heat balance. In response the licensee limited reactor power to 1915 MWth until the concern could be addressed. While determining the cause, I&C technicians made an adjustment to the feedwater temperature compensation circuit during a surveillance. This adjustment accounted for a large portion of the disagreement. A heat balance comparison performed after this adjustment resulted in a 5 MWth difference. The licensee returned to full power operation (1930 MWth) at 2:50 p.m. on August 13, 1992. While the difference was acceptable to the licensee, they were still investigating the cause of the difference and plan to address the cause once identified. The licensee's actions to address this issue were acceptable to the inspector.

EMRV acoustic monitor NR108B was declared inoperable at 6:30 p.m. on August 13, 1992, due to a low bias signal from the accelerometer in the drywell. A 48 hour TS LCO action statement was entered (TS 3.13.A.3). See section 3.4 for additional information. The

EMRV acoustic monitor was returned to service at 5:00 p.m. on August 14, 1992, after completion of repairs and testing.

The licensee identified a potential safety concern on August 18, 1992, that was reported to the NRC as a condition outside their design basis for 10 CFR 50, Appendix R requirements. The concern related to the potential for a hot short in the isolation condenser train used during remote shutdown operations. See section 1.6 for addition details.

During the inspection period the unit scrammed on two separate occasions. The first occurred from 100% power on August 22, 1992, at 12:55 p.m., when a component in the feedwater control system failed. See section 1.2 for additional details. The second scram occurred while in intermediate range monitor (IRM) range 8 on August 24, 1992, at 8:50 a.m., when the internal bypass on the number 2 stop valve failed open. See section 1.3 for additional details.

In response to NRC Bulletin 92-01 on the failure of Thermo-Lag 330 fire barrier material the licensee had made a determination that the fire barriers in the areas affected were still operable. The NRC reviewed this response and requested a discussion with GPUN to address this issue further. This discussion was held via telephone on August 24, 1992, with participation by NRC resident, regional personnel, NRR personnel, and GPUN personnel. After this discussion, the licensee agreed to re-institute the fire watches for Bulletin 92-01 subject areas where Thermo-Lag 330 fire barrier material had been installed. The NRC is still reviewing this issue generically and will continue to review this item as additional information and licensee bulletin responses are received.

A plant startup commenced at 10:00 a.m. on August 25, 1992. While performing the IRM range 6 to 7 correlation a half-scram signal occurred twice while removing the bypass of IRMs using bypass switch number 1. The second half-scram was accompanied by a high-high alarm without a scram signal on an IRM in the other channel of the reactor protection system (RPS). The group shift supervisor halted the startup until the problem could be investigated and corrective actions developed. As corrective action each of the IRMs was tested to verify that a high-high alarm would generate a half-scram in RPS and a temporary procedure change was issued to limit the requirements to bypass the IRMs while ranging up. The licensee determined it was acceptable to continue the startup. At the end of the inspection period the reactor was in IRM range 9 with power being increased. The licensee has been concerned with electronic noise generated by the IRM bypass switches and had planned to replace them during the 14R outage. However, due to this problem the licensee plans to replace the switches with an improved model on August 31, 1992.

1.2 Reactor Scram Due to Faulty Reactor Level Control Circuit

At 12:55 p.m., on August 22, 1992, an automatic reactor scram occurred from 100% power due to low reactor water level. The reactor water level decrease was caused by the failure of a steam flow density compensation circuit within the feedwater control system. The failure of this component caused the steam flow signal to the steam flow/feedwater flow comparison portion of the feedwater control system to go to zero. This resulted in a 100% mismatch between the steam flow signal and feedwater flow signal, causing the feedwater control system to rapidly reduce feedwater flow. A low reactor water level alarm was received in the control room shortly after the density compensation circuit failure. Three seconds later, the automatic scram occurred.

At 1:15 p.m. on August 22, 1992, the group shift supervisor (GSS) declared an Unusual Event (UE) due to the reactor isolation caused by the low-low reactor vessel water level. Appropriate notifications were made to the State of New Jersey and the NRC. The licensee secured from the UE at 2:52 p.m. on August 22, after reactor vessel water level had been recovered and stabilized.

Following the scram, reactor water level continued to decrease to just below the low-low level setpoint of 86 inches above the top of active fuel (TAF). Several safety system actuations occurred at the low-low level setpoint as designed. These included main steam isolation valve (MSIV) closure, core spray initiation (no injection to the reactor occurred), and containment and reactor water cleanup (RWCU) isolations. The emergency diesel generators (EDG) started and idled as designed. Following the MSIV isolation, operators controlled reactor pressure with the isolation condensers. About 20 minutes after the scram, the A electromatic relief valve (EMRV) was manually opened as an alternate pressure control mechanism. The control room operators (CRO) noted that reactor level had risen to about 173 inches. Since initiation of an isolation condenser can cause a reactor level increase of about 10 inches, the CROs anticipated that using the isolation condensers at this water level would cause level to increase to the steam inlet lines of the isolation condensers (180 inches TAF). The EMRV was placed in service for about two minutes to maintain reactor pressure control after which the isolation condensers were placed back in service. Cold shutdown conditions were established at 9:30 p.m. on August 22, 1992.

An NRC inspector responded to the site to verify proper plant and operator response to the transient. The inspector reviewed plant data and logs, and interviewed operations shift and Post-Transient Review Group (PTRG) personnel. The inspector also reviewed the completed PTRG report (92-139). Based on the inspector's reviews, discussions, and observations, the plant and operators responded as expected to the steam flow/feedwater flow mismatch signal generated when the steam flow density compensation circuit failed. Declaration of the UE was appropriate. The failed component was replaced and a reactor startup commenced on August 24, 1992.

1.3 Reactor Scram Due to Malfunction of Stop Valve Internal Bypass

At 2:15 a.m., on August 24, 1992, the licensee commenced a reactor startup following replacement of the failed steam flow density compensation circuit (see section 1.2). The startup progressed smoothly until about 8:45 a.m. when the internal bypass on the number 2 stop valve (SV #2) failed open. The SV #2 internal bypass was being used to warmup the high pressure turbine in preparation for rolling the turbine. When the bypass failed opened reactor pressure decreased causing a swell in indicated reactor vessel level. Control room operators (CRO) responded to the increasing vessel level by reducing feedwater flow from 10% to zero and increasing reactor letdown flow from 75 gpm to 100 gpm. Feedwater was secured for a short period, 15 to 20 seconds, before vessel level started to decrease. As reactor level indications began to drop, feedwater flow was increased initially to 10%, then to 20%; letdown flow was decreased back to 75 gpm; and the SV #2 internal bypass valve was placed in the closed position to conserve vessel inventory. When the bypass valve was closed reactor pressure increased causing a shrink in indicated vessel level. This shrink caused vessel level to drop quickly below the low level setpoint of 140 inches above the top of active fuel (TAF) to about 138 inches TAF. As designed, a reactor scram occurred when vessel level decreased below 140 inches TAF. Reactor power was in range 8 on the intermediate range monitors (IRM). The transient lasted about 5 minutes from the initiating event until reactor water level was recovered and stabilized.

Engineering review by a turbine controls engineer determined that a mechanical feedback link in the SV #2 bypass control system failed. The setscrews used to lock the feedback link into position were either missing or their threads were stripped. This allowed the feedback link to slip quickly out of adjustment, causing the SV control system to open fully the SV #2 internal bypass and momentarily open SV #2.

At the completion of the last refueling outage (13R) in June 1991, the setting for this feedback link was adjusted and tested to verify proper operation. This was done under the observation and direction of the Technical Functions turbine controls engineers. Operation of the SV #2 internal bypass was normal until this event occurred. No maintenance has been performed on the feedback link since that time. The licensee reviewed the turbine control system and determined the only location where this arrangement of setscrews and feedback links is used is on the SV #2 bypass valve. The other two stop valves do not have internal bypasses. The licensee concluded that the failure was random in nature. During the outage scheduled for November 1992, the licensee plans to check the turbine controls for any indications of missing or damaged setscrews in other applications.

A post-transient review group (PTRG) was conducted to assess the plant and operator performance during this event. The PTRG concluded that the operators responded appropriately to the rising reactor vessel water level. Plant response was as expected to the decrease followed by an increase in reactor pressure associated with the SV #2 internal bypass valve going full open then being closed. The swell and shrink in water level were consistent with the reactor vessel pressure changes. The PTRG recommended that this type of plant response be incorporated into the simulator response to plant transients.

The inspectors reviewed the PTRG report, plant logs, computer generated plant response plots for reactor vessel level, power, feedwater flow, steam flow, and pressure, and discussed the event with plant operators, PTRG personnel, engineering personnel, and operations department personnel. Based on these observations, the inspector concluded that the plant responded as designed, operator response was appropriate, engineering review of the cause of the failure was timely, and the PTRG adequately assessed plant and operator response.

Following repair and testing of the feedback link, the plant was being returned to operation. At 12:37 p.m., on August 25, 1992, the reactor was critical and power was being increased. By the end of the inspection period the reactor was in IRM range 9 and increasing.

1.4 Shift Turnover

The inspectors performed extended observations of several control room shift turnovers during the inspection period. The shift turnovers were assessed for overall quality and conformance with the requirements of Procedure 106, "Conduct of Operations," Revision 66. Overall, the inspectors concluded that control room shift turnovers are sufficiently detailed and performed in accordance with Procedure 106 requirements.

Control room operator shift turnovers were thorough and appropriate. Procedure 106, Attachment 3, Control Room Operator Turnover Checklist, was prepared and signed as prescribed in the procedure. The oncoming and offgoing operators participated in a full control room panel walkdown as prescribed by Procedure 106, Step 4.3.4. Open discussion was encouraged by the lead control room operators directing the walkdowns.

Group shift supervisor (GSS) and group operating supervisor (GOS) turnovers were also thorough. In addition to system status, appropriate additional information was discussed such as the status of ongoing or recently completed maintenance and surveillance activities, currently effective operations department directives, recently issued temporary procedure changes, and planned activities for the upcoming shift. The oncoming GSSs and GOSs were observed performing control room panel walkdowns shortly after completing the shift turnover. Attachment 2 to Procedure 106, GSS Turnover Checklist, was prepared by the departing GSS for each turnover. While the level of discussion during GSS/GOS turnover was often quite detailed, the inspectors noted that the completed checklists were not particularly detailed and often referred to the plant status board in the GSS office for applicable information. The inspectors commented that the licensee should consider whether the practice of routinely referring to the GSS status board on the turnover checklist was meeting their intentions in terms of historical documentation of GSS turnover.

1.5 Followup of Equipment Operator Round Deficiencies (TI 2515/115)

On March 6, 1992, GPUN initiated an investigation of auxiliary operator activities after a concern was identified related to deficiencies in plant records and poor record keeping practices. This review was conducted by an independent team of Three Mile Island (TMI) security department personnel in two phases. The initial phase of the investigation focused on the specific concerns identified to the licensee. The second phase took a historic look at security records and log readings recorded on the three plant operator tour sheets compared to respective plant operating conditions.

During the initial phase, 41 employees were interviewed. Also, operations shift schedules, security computer keycard listings, radiation work permit (RWP) lists, various area tour sheets, control room logs, and training records were reviewed during the initial phase of the investigation. During this phase of the investigation some of the concerns identified were determined to require corrective action while others were unfounded. Details of the initial phase of the investigation were provided to the NRC in a letter dated May 5, 1992.

The second phase of the investigation focused on the accuracy of the information recorded on plant operator tour sheets. This phase reviewed site security records and operator tour sheets from December 1, 1991, through February 29, 1992. During this phase of the investigation, the licensee identified that five non-licensed equipment operators (EO) recorded information on their plant operator tour sheets when, based on security records, they could not have performed the actions or obtained the information required by the tour sheet. The majority of the deficiencies involved EOs initialing their logs for entry into the upper cable spreading room to perform an inspection of the area for any unusual conditions. No equipment readings were recorded during the inspection of the upper cable spreading room. One deficient record involved an EO that recorded readings for the 24 vdc system that provides power to the neutron monitoring system and initialled that this action was done when no entry was recorded for that EO during that time, based on a review of security records. Details of the second phase of the investigation were provided to the NRC in a letter dated May 13, 1992.

As a result of the second phase of the investigation, the licensee disciplined the five non-licensed operators by suspending them for five days without pay. Each of the suspended equipment operators was required to meet with the Plant Operation Director and Plant Operation Manager so the importance of accurate log keeping, honesty, and integrity could be reinforced.

When the initial concern was identified GPUN started a corrective action plan to determine the extent of the problem with equipment operator tours. This action plan involved discussion of the concerns with licensed and non-licensed operators; tours with the equipment operators accompanied by their immediate supervision (group operating and group shift supervisors, GOS and GSS); obtaining input from the EOs on the need to modify tour sheets; review of log sheets by GOS or GSS at the end of each shift, with those not meeting operations department standards for log keeping returned to the responsible EO for correction; arranging for operations quality assurance (OQA) personnel to audit independently logkeeping practices; reviewing logkeeping requirements and standards with radwaste operators, chemistry technicians, and their supervisors; revising the tour sheets based on input from EOs and other operations personnel; establishing a schedule of the required frequency of periodic, GSS/GOS supervised EO tours; revising the operator training program to communicate clearly management's expectations regarding tour activities; and revising the operator requalification program to ensure operator tour performance meets or exceeds clearly defined management expectations on each item of the tour sheets. Immediately following the identification of the concern, Operations management directed that each of the EOs be accompanied on their tours in each of the areas by either the GOS or the GSS to allow an assessment and feedback on the EO's performance. The inspectors accompanied several operators on their tours as documented in NRC Inspection Report 50-219/92-04.

The inspector reviewed the licensee's investigation reports, discussed the issue with senior plant management, reviewed the licensee's progress with their corrective action plan, and reviewed EO tour sheets on a random basis. During the discussion with the Manager, Plant Operations, the inspector was informed that a random review of EO security access records and EO tour sheets was being performed as a method of identifying any further record keeping concerns in addition to the actions directed by their action plan. GPUN has been aggressive in pursuing their corrective action plan. Several of the actions will continue as routine activities to ensure this type of event does not occur again. These include the periodic GOS/GSS accompaniment of EO on their tours, reviews of tour sheets at the end of the shift, and the OQA independent audits of EO logkeeping practices. The only items yet to be completed are the development of the changes to the operator training and requalification programs and these are scheduled to be completed by January 1993.

Overall, the inspector concluded that the licensee had been aggressive in pursuing the deficiencies with plant records identified in March 1992. The corrective action they have completed and planned should prevent recurrence, or identify EOs that have falsified records in a timely manner. While the licensee has been aggressive in pursuing this issue, the NRC is reviewing this issue generically to determine the appropriate course of action. Additional review and correspondence by the NRC may occur. Based on the inspectors reviews, observations, and discussions, the licensee has established a good process for the detection of any additional EO performance or plant logkeeping deficiencies.

1.6 Remote Shutdown Capability Potential Safety Concern

The licensee was performing a review of plant configuration with respect to industry information and NRC Information Notice 92-18 on the potential for loss of remote shutdown capability during a control room fire. During this review a potential safety concern (PSC) was identified based on a review of isolation condenser, shutdown cooling, and recirculation pump valve control system drawings. The configuration for the B isolation condenser valves, the E recirculation pump discharge valve, and the inlet and outlet header isolation valves for shutdown cooling are required for remote shutdown capability. The concern was that a hot short in the control room caused by a fire could damage the valve operator motors by causing them to overheat when excessive current is drawn during extended locked rotor operation. With the valve operator motors damaged the licensee's ability to remotely shutdown the plant would be hampered.

The protective features of the motor operated valves (MOV) control circuits include torque switches, position limit switches, and thermal overloads. In each case except the B inboard steam isolation valve for the B isolation condenser (V-14-33) the thermal overloads or the torque and limit switches provide some protection. In V-14-33 the thermal overload was jumpered out of the circuit. This was done to prevent V-14-33 from being rendered inoperable in the event there was a line break in the A isolation line outside of the drywell. The motor control center (MCC) for the B isolation condenser DC powered MOVs is located in the reactor building near the isolation condensers. While the thermal overload for the DC powered B condensate return isolation valve (V-14-35) is also jumpered, the torque and limit switches are located in the control circuit after the control room controls and still provide adequate protection to the valve operator motor.

To improve the licensee's ability to remotely shutdown the plant, information tags were located at the remote and local shutdown panels for each of the affected valves. The information tags tell the operators that it may be necessary to reset the thermal overloads at the MCCs of the valves in the event the valves do not operate from the remote or local shutdown panels. Once control is transferred to the remote or local shutdown panels, a hot short in the control room does not affect the ability to control the valves from the remote/local panels. In addition, for V-14-33, the operators have been directed that it may be necessary to manually control the valve position using the valve manual operator located on the 75 foot elevation of the reactor building. In an effort to ensure all the control room operators were aware of the concern, Operations management issued an operator aid that clearly delineates the actions in the event the control room must be evacuated due to a fire.

As permanent corrective action the licensee plans to modify the control circuits for the affected valves during the upcoming refueling outage scheduled for late November 1992. The modification will place the torque and limit switch functions of the control circuit after the control room control switches eliminating the concern of damaging the effected valves in the event of a hot short in the control room.

The inspector reviewed the PSC package, discussed the concern with plant management, reviewed the drawings associated with V-14-33 and V-14-35, verified that the information tags were located at the shutdown panels, and reviewed the operator aid located at the shutdown panels. Based on the inspector's observations, reviews, and discussions, the inspector concluded that the licensee has taken appropriate compensatory actions to minimize the effects of a hot short in the control room on their ability to remotely shutdown the plant. Installation of the modification remains necessary to improve the ability to remotely shutdown the plant in the event the control room becomes uninhabitable. The inspector did not have any immediate concerns with the continued operation of the plant due to hot short concerns.

1.7 Facility Tours

The inspectors observed plant activities and conducted routine plant tours to assess equipment conditions, personnel safety hazards, procedural adherence, and compliance with regulatory requirements. Tours were conducted of the following areas:

- control room
- cable spreading room
- diesel generator building
- new radwaste building
- old radwaste building
- transformer yard
- intake area
- reactor building
- turbine building
- vital switchgear rooms
- access control points

Control room activities were found to be well controlled and conducted in a professional manner. Inspectors verified operator knowledge of ongoing plant activities, equipment status, and existing fire watches through random discussions. As the site is preparing for the upcoming outage, material is being staged in the plant. Controls have been adequate to minimize the effect of this additional material on plant operations.

2.0 RADIOLOGICAL CONTROLS (71707)

During entry to and exit from the radiologically controlled area (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 and verified that personnel were complying with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area.

3.0 MAINTENANCE/SURVEILLANCE (62703,61726)

3.1 Main Steam Line High Flow Sensor Test and Calibration

On August 3, 1992, the inspector observed the performance of surveillance procedure 619.3.005, Rev. 23, "High Flow in the Main Steam Line Test and Calibration," for two of the eight main steam line high flow sensors (RE22D and RE22H). The test was successfully completed. The technicians performing the testing communicated well with each other and with the control room. Properly calibrated test equipment was used.

The inspector noted a questionable work practice during the test. On several occasions the technicians stood on a portion of the scram discharge volume (SDV) drain line to gain better access to the test plugs on top of each high flow sensor. The SDV drain line is a 2 inch header located about 1 foot away from the drywell outer shield wall and is raised about 1 foot off the floor. The RE22D and RE22H sensors are located at about eye level along the drywell outer shield wall just above the SDV drain line. While the SDV drain line appeared to be capable of supporting the weight of the technicians, the inspector found the use of this piping as a step stool to be neither appropriate nor necessary. GPUN acknowledged the inspector's comments and informed all maintenance technicians that this practice was inappropriate. GPUN is assessing how to improve technician access to the test plugs while protecting the SDV drain line.

3.2 Condensate Demineralizer Resin Transfer

On August 10, 1992, the inspector observed a portion of the number 2 condensate demineralizer resin transfer to the final rinse and storage tank. The resins was being transferred in preparation for air-bump-and-rinse-operation (ABRO) to clean the resin for reuse. The transfer was being performed using procedure 319, Rev. 23, "Condensate Demineralizer Resin Regeneration and Transfer System." The operators performing the transfer were knowledgeable of the procedural requirements. Radiological controls technicians provided good coverage of the transfer. Overall, the transfer was well controlled and conducted.

3.3 Core Spray Pump Suction Flange Bolt Replacement

On August 12, 1992, the inspector observed the replacement of the suction flange bolts for core spray booster pump NZ03A. The bolts were being replaced one-for-one, allowing the core spray system to remain operable during this maintenance activity. Work was controlled using job order number (JO#) 39910 as a corrective maintenance activity to address a non-conforming condition identified in material non-conformance report (MNCR) 92-0065. The MNCR was written to document that there was insufficient thread engagement on the suction flanges of the core spray booster and main pumps.

The inspector reviewed the job package, the MNCR disposition, the engineering instructions for torque specifications on the replaced bolts, and observed the mechanics performing the maintenance. Adequate engineering review was done to support the one-for-one replacement of the suction flange bolts, the mechanics used good work practices while replacing the bolts, and the torque wrench being used was in current calibration. Overall, the maintenance was well controlled and conducted.

3.4 Electromatic Relief Valve Acoustic Monitor Maintenance

On August 14, 1992, the inspector observed the maintenance to swap the acoustic monitor for electromatic relief valve (EMRV) NR108B from the primary accelerometer to the backup accelerometer located on the EMRV. The acoustic monitor provides indication of the position of the EMRV. The low bias alarm for the B EMRV acoustic monitor locked in on

August 13, 1992, at 6:30 p.m., resulting in the acoustic monitor being declared inoperable. With the acoustic monitor inoperable, the licensee entered a 48 hour technical specification shutdown limiting condition for operation (TS LCO) action statement.

The work was done in the traversing incore probe (TIP) shield room. Work was controlled using JO# 40960 and radiological work permit (RWP) 92-721. The TIP shield room is controlled as an exclusion area because of the potential for very high radiation levels. With the TIP shield room an exclusion area and the short duration of the TS LCO action statement, coordination among maintenance, operations, quality assurance, and radiological controls was required to ensure the work was completed in a timely manner.

The inspector observed the splicing of the leads from the backup accelerometer into the acoustic monitor circuit for EMRV NR108B in the TIP shield room, attended the radiological controls prejob brief, and reviewed the job package and RWP. The inspector noted that the instrument and control (I&C) technicians performing the work were knowledgeable of the job package requirements, coordinating their efforts well with the quality assurance inspector to ensure the work was properly performed and inspected. Radiological support was good while work was performed in the TIP shield room. Application of the Raychem splices was well controlled, with the required hot work authorization obtained before work began. Overall, the inspector concluded that the work was well coordinated, planned, and executed.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707,40500)

4.1 Plant Changes, Tests, and Experiments (10 CFR 50.59) Review

Between July 14 and July 17, 1992, the NRC Project Manager for Oyster Creek conducted a review of the licensee activities associated with the performance of safety evaluations. Safety evaluations were performed to support changes to the facility as described in the final safety analysis report (FSAR) and to support safe operation of the plant when the changes did not affect the description of the facility in the FSAR. The process used by GPUN to review changes, facility modifications, tests, or experiments was reviewed previously by the NRC in 1988, 1989, 1990, and 1991. During the current review no significant changes were noted to the safety evaluation process as described in corporate procedure 1000-ADM-1291.01, Rev. 9, "Safety Review Process." The licensee's safety review process continues to be acceptable.

The Project Manager reviewed 3 procedure changes and 22 plant change safety determinations (see attachment 1). For each change the corporate procedure for safety reviews was correctly followed. The safety evaluation to support the diesel fuel oil storage tank replacement (SE408815-001) was very thorough and well organized.

During the review the NRC Project Manager did not identify any instances where the licensee had failed to address an unreviewed safety issue. In conclusion, the licensee continues to provide an adequate mechanism for 10 CFR 50.59 determinations as described and implemented using corporate procedure 1000-ADM-1291.01.

5.0 EMERGENCY PREPAREDNESS (71707,82301)

5.1 Quarterly Emergency Preparedness Exercise

On August 19, 1992, the inspector observed a portion of the quarterly emergency preparedness exercise. The exercise scenario was security based and resulted in simulated challenges to the plant. The objective of the exercise was to check the coordination between security and operations, and between security and the operations support center (OSC).

The inspector observed the response in the technical support center (TSC) late in the drill. TSC response was appropriate for the conditions being encountered. Security search and rescue teams were being adequately tracked by the OSC as required. Communication equipment problems that were encountered during the drill were quickly overcome and did not significantly hamper the response from the TSC. During the critique held on August 20, 1992, the licensee adequately identified the equipment and performance weaknesses observed during the exercise.

The inspector concluded that the licensee adequately conducted the quarterly exercise to demonstrate their ability to respond to emergency conditions and used the exercise to identify areas for improvement.

6.0 SECURITY (71707)

During routine tours, 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 isolation zones were free of obstructions. Inspectors examined vital area access points and verified that they were properly locked or guarded and that access control was in accordance with the Security Plan.

7.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (40500,71707)

7.1 Management Observation Teams

Background

The NRC Diagnostic Evaluation Team (DET) conducted in November and December 1990 noted a potential weakness in supervisory oversight after observing several instances of poor work practices and worker radiological control practices. The DET found a number of inconsistencies in observed work practices resulting from inattention to detail and an apparent lack of questioning attitude on the part of workers and their first-line supervisors. In addition to other actions, the licensee has been addressing this issue through the implementation of management observation teams.

The intent of the observation team was to provide for direct management observation of randomly selected plant activities so that both the work being performed and the interaction between the workers and the first-line supervision could be evaluated. In some cases, an extended observation of one activity was performed. In other cases, the observation team toured the facility and observed smaller portions of several activities. In addition to the discovery of problems at the worker/first-line supervisor level through observation, the observation team concept was also intended to help promote a desired change in the quality of work practices through the increased presence of management in the field. Rather than simply noting observed deficiencies, the observation team charter also includes constructive coaching of the worker and/or the first-line supervisor, as necessary, to remedy a noted deficiency on the spot. The effectiveness of the observation team effort relies on the ability of the observers to provide this constructive criticism in the proper manner so as to gain the acceptance and confidence of those being observed.

Assessment

The inspectors reviewed the reports which documented the results of the management observation team tours conducted since November 1991. The inspectors also accompanied an observation team into the field. Overall, the inspectors found that participation in the management observation teams has not been aggressive and that improvements in the quality of observations and reporting are needed.

Since November 1991, about 30 management observation team tours have been performed. A review of the reports which documented these tours found them to be more of a description of the activities observed than an assessment of worker and first-line supervisor performance. While coaching may have been performed during some of these tours, it was not often reflected in the documentation. These comments are similar to those provided after inspector review of the first management observation team reports from observations performed in September and October 1991. The inspectors also noted that a large portion of the management observation team effort was being accomplished by radiological controls department management. As such, most of the tours have focused on radiological safety and industrial safety practices. While these areas should be part of the observations, more diverse management participation would allow for more informed observation of technical work performance.

On August 13, 1992, the inspector accompanied an observation team consisting of three site managers into the field. Work was observed on the refueling floor, at the chemistry sample sink on the 51 ft elevation of the reactor building and on the control rod drive hydraulic control units (HCU) on the 23 ft elevation of the reactor building. While the observers occasionally tended to focus on plant material condition items, some effective coaching was given to a chemistry technician and several radiological controls technicians. The observers were prompted by the inspector to question an improper contamination control practice noted during a diagnostic check of an HCU scram inlet val

The inspectors concluded that management observation team efforts thus far have not been aggressive and more participation from managers who can provide informed assessment of work performance techniques is needed. The documentation of observation tour results lacks detail of coaching provided and worker response to coaching. The licensee acknowledged that improvements could be made in the performance and documentation of the management observation team tours. A training session has been scheduled for late August 1992 to discuss observation techniques and reemphasize expectations for the management observation team process.

7.2 In Office Review of Licensee Event Reports

NRC inspectors reviewed the following LER and verified appropriate reporting, timeliness, complete event description, cause identification, and complete information. In addition, the need for on site review was assessed.

LER NO.	DESCRIPTION
92-05	Loss of Offsite Power due to a Nearby Brush Fire

This LER was written to document the effects of an offsite fire that occurred on May 3, 1992, on Oyster Creek. NRC review of this event is documented in NRC inspection report number 50-219/92-12. No additional onsite followup is required. The LER adequately discussed the event, identified the cause, and was issued in a timely manner.

8.0 EXIT MEETINGS AND INSPECTION HOURS SUMMARY (40500,71707)

8.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to John Barton, Vice President and Director Oyster Creek, and other senior licensee management on August 27, 1992. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report. The inspection consisted of normal, backshift, and deep backshift inspection; 16.4 of the direct inspection hours were performed during backshift periods, and 7.0 of the hours were deep backshift hours.

8.2 Attendance at Management Meetings Conducted by Other NRC Inspectors

The resident inspectors attended exit meetings for other inspections conducted as follows:

July 24, 1992	Report No. 50-219/92-15	Radiological Controls
July 31, 1992	Report No. 50-219/92-17	Security

At these meetings the lead inspector discussed preliminary findings with senior GPUN management.

ATTACHMENT 1
A. PLANT CHANGES SELECTED TO REVIEW

Modifications Safety Evaluation No.	Title
SE-408773-010	Replacement of Valves V-3-87 and V-3-88
SE-408773-007	Feedwater Drain and Vent Addition
SE-402953-010	RPV Head Vent Valve Addition
SE-408815-001	Diesel Fuel Oil Storage Tank Replacement
SE-409745-001	Tornado Missile Shield
SE-312400-010	TBCCW, SEP and SDC Heat Exchanger DP Gauges
SE-323560-003	Installation of Test Plugs for Control Rod Scram Insertion Time Test and Valve IST Test
SE-402916-001	Core Spray Alarm Modification
SE-402938-001	RWCU Drywell Penetration Pipe Replacement
SE-402939-001	Drywell Chiller Unit Piping Modification
SE-402872-001	Torus Oxygen Sample Line Isolation Valves Modification
SE-323636-002	Reactor Building Closed Cooling Water Corrosion Monitoring
SE-328279-001	Core Spray/ADS Logic Modification
SE-402857-003	SWRM Upgrade Phase II
SE-942100-002	Repaired Transformer M1A Installation and Reconnection
SE-402933-002	Modification of Accumulator Piping
SE-000212-018	Remove Core Spray Min. Flow Check Valves

ATTACHMENT 1
A. PLANT CHANGES SELECTED TO REVIEW (con't)

Modifications Safety Evaluation No.	Title
SE-408773-004	Temperature Monitoring Systems Replacement, C.R. Panels 12XR and 10R
SE-402953-003	Installation of Hydraulic Snubbers on RWCU Pressure Switches
SE-402953-012	Installation of Control Air Trip Valves on V-26-16 and V-26-18
SE-402949-001	Reactor Building Construction Power Upgrade
SE-402939-004	Drywell Power Improvement

B. PROCEDURE CHANGES SELECTED TO REVIEW

Safety Evaluation	Title
----------------	Process Control Plan for Transfer and Solidification System
----------------	Augmented Offgas System Operation
----------------	Alternate Water Supply to AOG Heat Exchanger