U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	
Docket No.	50-219
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:	February 23, 1992 - March 28, 1992
Inspectors:	T. Frye, Reactor Engineer, DRP P. Kaufman, Project Engineer, DRP J. Nakoski, Resident Inspector D. Vito, Senior Resident Inspector
Approved By:	W. H. Ruland 4/17/92 W. H. Ruland, Chief Date Reactor Projects Section 4B

Inspection Summary: This inspection report documents routine and reactive inspections conducted during day shift and backshift hours of station activities including: plant operations; radiation protection; 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. An unresolved item was opened on the installation of a non-QA approved fuse in the 1C breaker control and indicating power circuit. A violation of station procedures was identified relating to the performance of electrical component checkoff lists. An apparent violation of 10 CFR 50.47.(b)(8) and a June 12, 1984, Confirmatory Order relating to the maintenance and testing of the Technical Support Center ventilation system was identified.

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The NRC inspection manual inspection procedure (IP) or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
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Plant Operations

Overall, the plant was operated in a safe manner. Control room activities continue to be well conducted, with a strong management presence. A concern was raised with the performance of tours and the recording of logs by non-licensed equipment operators (EOs). GPUN has initiated an investigation to determine the extent of this concern. NRC observation of EO tours found that clear guidance on management expectations of tour requirements had not been provided.

Review of a core spray system electrical component checkoff list identified that it had not been performed as required by station procedures and did not contain all of the breaker positions required to verify the system was in standby readiness. Operations response to the loss of the 1C bus undervoltage (UV) protective relays was timely.

GPUN's initial decision to initiate a plant shutdown and request a temporary waiver of compliance from the requirement to place each of the UV devices in a tripped condition (rendering the 1C emergency bus unavailable), while later determined not to be required, reflected a safety conscience attitude.

Radiological Controls

No notable observations were made.

Maintenance/Surveillance

The maintenance and surveillance testing observed during the inspection period were generally well controlled and conducted. Corrective maintenance performed in response to the loss of the 1C UV protective relays was timely. However, the installation of a non-qualified fuse during this work resulted in the need to perform rework and a second entry into a 30 hour technical specification shutdown action statement.

Engineering resolution of an automatic synchronization circuit problem during surveillance testing of the number 2 emergency diesel generator was timely and thorough.

The erosion/corrosion program has substantially improved. The program has evolved from engineering judgement based on historical data to a program capable of accurately predicting the location of pipe wall thinning using both historical data and computational analysis methods (CHEC and CHECMATE programs). These methods will be used during the 14R refueling outage to determine areas where inspections should be performed.

Engineering and Technical Support

Material leaching from the concrete ceiling of the 75 ft elevation of the reactor building has built up on core spray and refuel cavity cooling piping. The licensee performed an engineering analysis, based on historical and recent sample results, on the effect this leachate had on the piping. The analysis concluded that there was no need to remove this material from the piping.

Emergency Preparedness

The lack of maintenance and testing of the technical support center (TSC) ventilation system from completion of construction until December 1991 was an apparent violation of NRC requirements and will be the subject of a pending enforcement conference. An inadequate or non-existent turnover of the facility to the plant after construction was completed, appears to have been the cause for the failure to perform the required maintenance and testing.

Safety Assessment and Quality Verification

Performance concerns with EO tour and logkeeping practices and the failure to complete the core spray electrical component checkoff list as required by station procedures by licensed operators when viewed with the installation of the non-qualified fuse in the 1C UV protective relay circuit raises a concern with the performance expectations provided to personnel working outside the control room.

DETAILS

1.0 OPERATIONS (71707,71710,93702)

1.1 Operations Summary

The unit started the period at 100% power. On February 25, 1992, at 1:45 p.m., power was decreased to 95% to remove the "A" reactor coolant pump from service to allow stoning the slip ring of the motor-generator (MG) set. By 6:00 a.m., on February 26, 1992, the unit was back at 100% power. Throughout the period the licensee was in and out of the low intake level abnormal procedure, 2000-ABN-3200.32, revision 9, "Response to Loss of Intake," due to lower than normal tides. While the intake levels were lower than normal, impact on plant operation was minimal.

On March 3, 1992, an equipment operator reported that he heard flow in one of the fire suppression sprinkler system lines for the condenser bay. A tour of the condenser bay revealed that a sprinkler head for deluge system 2 had failed and was leaking. The system was isolated and the sprinkler head replace by 1:53 p.m. on March 4, 1992.

On March 4, 1992, at 12:20 p.m., the control room received a report of smoke in the turbine building south mezzanine. When the equipment operator (EO) and group operating supervisor (GOS) responded, they found the breaker for valve V-3-18 (A north condenser backwash valve) on motor control center (MCC) 1A11A smoking. The GOS and EO de-energized and racked out the breaker. No fire was evident; however, the breaker was cooled using a CO_2 extinguisher. The GOS and EO inspected the other breakers and breaker cubicles in MCC 1A11A and found no indications of water or component damage. The cause of the overheating was attributed to a partial ground on the primary side of the control transformer caused by water intrusion into the breaker cubicle from conduit that is routed into the condenser bay. While the root cause analysis has not yet been completed, a probable source of the water was the leaking sprinkler head identified on March 3, 1992. The control power transformer and associated wiring were replaced. Testing of the remaining breaker components showed that replacement was not necessary. The licensee is evaluating methods to prevent water intrusion in the future.

On March 12, 1992, at 10:33 a.m., a firewatch located in the 4160V switch gear room reported sparks coming from the 1C breaker and that the undervoltage (UV) relay indicating lights had gone out. The 1C breaker feeds the "C" 4160V emergency bus which powers ESW pumps, core spray pumps, and other safety loads. The loss of indicating lights for the UV relays was the initial sign that the control and indicating power fuse for the 1C bus UV relays had blown. See section 1.3 of this report for additional details. Reactor power was decreased as required by the action statement of technical specification (TS) 3.0.A (30 hours to cold shutdown) until 10:23 p.m. on March 12, 1992, when the indicating light sockets were repaired and the control and indicating power fuse replaced. Reactor power reached 59%. By 12:45 a.m., on March 13, reactor power was returned to 100%. A second entry into TS 3.0.A was required on March 13, 1992, at 9:43 p.m., to replace the fuse installed earlier because the replaced fuse was non-qualified. The fuse was replaced and the action statement exited by 10:52 p.m. No additional shutdown was initiated.

While recovering from the shutdown on March 12, 1992, the 1-4 circulating water pump would not restart. The licensee determined that the motor field would flash to start the motor turning, but would then collapse, preventing the motor from running. The licensee attempted several pump starts between March 12 and 15, 1992. The pump finally started on March 15, 1992, at 9:35 a.m. While the 1-4 circulating water pump was out-of-service, the licensee was in a 14 day environmental permit action statement because the intake to discharge differential temperature was greater than 23°F.

Routine maintenance was performed on the "A" control rod drive (CRD) pump between March 13 and 17, 1992. This placed the unit in a 7 day shutdown TS action statement. After the maintenance was completed, the "A" CRD pump was returned to service. However, on March 26, 1992, at 9:34 a.m., the pump was again removed from service due to high motor vibrations. The cause of the high motor vibrations was attributed to an imbalance in the pump-to-motor coupling. The imbalance was due to both the pump side and motor side locking keys located radially in the same orientation and the grease ports for the pump and motor sides were not diametrically opposed. This mass imbalance was sufficient for the motor vibrations to be out of specification. After correcting the imbalance at the coupling, the pump was retested and returned to service at 2:50 p.m., on March 27, 1992.

A trip of the reactor building ventilation system that occurred on March 20, 1992, resulted in the initiation of deluge system 6. See section 1.5 of this report for additional details. Prior to this reactor building ventilation trip, two other trips had occurred. The previous trips occurred on March 18, 1992, at 10:28 a.m., and 3:15 p.m. No cause for these previous trips was identified and the reactor building ventilation system was quickly restarted following each trip.

On March 23, 1992, at 9:43 a.m., a decrease in reactor power was initiated to allow the stator cooling water filter to be replaced. Reactor power was decreased to about 30% by 3:30 p.m. The generator was then unloaded to about 83 MWe to allow removing the stator cooling water system from service. This required 3½ bypass valves to be opened. The stator cooling water system was removed from service, the filter replaced, and the system was returned to service by 6:13 p.m. Generator output and reactor power were increased and full power was reached at 11:45 p.m. on March 23, 1992. Reactor power was controlled using bypass valves for about two hours.

Reactor power remained at 100% until the end of the period. At 7:08 p.m., on March 28, 1992, a combination of heavy grass and low tides resulted in the licensee securing the 1-1 circulating water pump to maintain intake level. Overall plant operation was not affected by securing the 1-1 circulating water pump.

1.2 Core Spray System I Walkdown

The inspector performed a walkdown inspection of core spray system I to verify the system was in standby readiness to support operation. This inspection included a review of the technical specifications (TS) and final safety analysis report for the core spray system to determine the limiting conditions of operation and the surveillances required to assure system operability. Station procedure 308, Emergency Core Cooling System Operation, was reviewed to determine the equipment lineup and instrumentation indications required to ensure that the core spray system was in a standby condition, ready for operation. The operating procedure valve checkoff lists were compared against the core spray piping and instrument diagram (P&ID) to ensure that the checkoff list placed the core spray system in a configuration to support operation.

The inspector walked down the accessible portions of core spray system I. In addition, the inspector compared the operating procedure valve and electrical checkoff lists against the as-found valve and breaker positions to verify that the system was lined up in accordance with the operating procedure. System and component conditions were observed for any indications of degradation which could impede proper system operation. The core spray system P&ID was compared against the as-found system to verify that the P&ID accurately reflected the as-built system configuration. System instrumentation was verified to have current calibration dates and was observed for proper indication when applicable. The control room pump, valve, and logic switch lineup was verified correct as required by the operating procedure. The control room copy of the checkoff lists were reviewed and found to be complete.

The following completed surveillance procedures were reviewed. The inspector concluded that these surveillances were being completed within the frequencies specified by TS.

610.4.002, Rev 24, "Core Spray Pump Operability Test"

610.4.003, Rev 20, "Core Spray Valve Operability and In-Service Test"

610.3.105, Rev 20, "Core Spray System 1 Instrument Channel Calibration, Test and System Operability"

610.3.004, Rev 14, "Core Spray Header Differential Pressure Test and Calibration"

During review of the core spray P&ID against operating procedure valve checkoff lists, two minor valve position discrepancies were noted. Core spray P&ID 885D781, revision 36, shows core spray header d/p instrument root valves V-20-154 and V-20-155 as normally closed. Instrumentation diagram P&ID 112C2845, revision 7, shows these valves as open, their correct position. The valve checkoff list for these valves, contained in Station Procedure 410, "Placing Instrument Racks RK01, RK02, RK03 and RK04 In Service," revision 17, also positions these valves in the required open position. The incorrect valve positions on core spray P&ID 885D781 were brought to the attention of the GSS and a field change request was initiated to correct the drawing. The instrumentation associated with these valves were observed by the inspector to be indicating normally, providing an indication that the valves were in the open position.

On March 5, 1992, the inspector identified two discrepancies on the core spray system electrical checkoff list contained in procedure 308. Both discrepancies involved the breaker description on the checkoff list and the breaker label on the electrical panel not being in agreement. The first discrepancy involved breaker #11 on 125 VDC Panel F. On the electrical checkoff list the breaker description was "Panel 18R/19R Alternate Power Source for Rx Water Level Lo-Lo" and was required to be in the "on" position. Breaker #11 on 125 VDC Panel F was labeled as "LSP-1A2 Control Power" and was in the "on" position. The other discrepancy involved breaker #17 on Panel 4. On the checkoff list the breaker description was "Panel 2F Solenoid Valves V-6-201, V-6-202, V-6-203, V-6-204, V-6-205, V-6-206, V-6-430, V-6-431" and was required to be in the "on" position. Breaker #17 on Panel 4 was labeled "Panel 1F/2F Recorders & Digitals" and was in the "on" position. These two discrepancies were brought to the attention of the group operating supervisor (GOS). The inspector requested that the GOS determine whether the breakers were labeled incorrectly on the panels or whether the checkoff list was wrong.

About one hour later, the GOS informed the inspector that the checkoff list was in error in that the correct breakers were not specified. The correct breaker for "Panel 18R/19R Alternate Power Source for RX Water Level Lo-Lo" was breaker #15 on 125 VDC Panel F. The correct power supply for "Panel 2F Solenoid Valves V-6-430/V-6-431" was breaker #19 on panel VACP-1. Solenoid valves V-6-201, 202, 203, 204, 205, and 206 were no longer supplied from this power source. Per field change notice C050187, valves V-6-201, 202, 203, and 204 were removed from the system. Valves V-6-205 and V-6-206 are manual valves.

The inspector accompanied an equipment operator and verified that breaker #19 on VACP-1 and breaker #15 on 125 VDC Panel F were in the required "on" position. The GOS stated that a temporary change (TC) would be issued to procedure 308 to correct the electrical checkoff list to reflect the correct breakers to be positioned to ensure core spray system I standby readiness. The inspector verified that TC 3-6-92-9 was issued on March 6, 1992, and adequately corrected the errors in the electrical checkoff list in procedure 308.

The licensee issued deviation report 92-114 to document the discrepancy with the checkoff list, initiate additional corrective actions, and a root cause determination. Part of the corrective action to determine the extent of the checkoff list discrepancies included walking down the electrical portions of safety related systems. These walkdowns consisted of comparing the checkoff list description of breakers to the breaker labeling and then comparing the checkoff lists against the prints to verify that the proper power supplies were listed on the checkoff lists. The following systems were checked: standby gas treatment system, containment spray, core spray, automatic depressurization system, standby liquid control, containment integrity and atmosphere control, isolation condenser, reactor water cleanup, and shutdown cooling.

Several additional electrical checkoff list discrepancies were identified by the licensee as a result of these system walkdowns. As with the two discrepancies found by the inspector, none of the discrepancies found by the licensee involved a breaker being out of its required position and the affected safety related systems were operable. All of the discrepancies found by the licensee, including the two found by the inspector, could be placed into two general categories. One group of discrepancies involved inadequate or incorrect breaker labeling on the panel. The other discrepancies involved the wrong breaker being listed on the electrical checkoff lists as the power supply for certain components. All breakers which were incorrectly identified on these checkoff lists were verified to be in the proper position either by being included on a properly completed checkoff list which had been performed for a different system or the breakers in question were actually verified elsewhere in the same checkoff list. This was true for all breaker discrepancies except one, breaker #19 on panel VACP-1, which had been identified by the inspector. The position of this breaker was not verified by a two person check on any previously performed checkoff list.

The licensee has initiated deviation reports to document all breaker discrepancies found. Temporary changes are planned for all of the affected operating procedures to correct the electrical checkoff lists. The licensee will re-perform these corrected portions of the checkoff lists to ensure that a current, complete system lineup is maintained.

The inspector concluded that this event was in violation of NRC regulations. Electrical checkoff list 308-2 was not properly updated as equipment and component power supplies were changed. This resulted in the checkoff list, last performed on May 2, 1991, not verifying the position of the correct breakers required to provide power for components in the emergency core cooling system as required by station procedure 308, section 4.3, "Placing the Emergency Core Cooling System in Standby Readiness." In addition, station procedure 108, revision 54, "Equipment Control," paragraph 4.10.8, requires that during the conduct of equipment verifications, each component shall be checked to ensure that a correct component label is present and labeling deficiencies shall be reported to the GSS for disposition. Failure to perform this action during the equipment verification resulted in the required power supply breakers not being identified on checkoff list 308-2 from at least May 2, 1991, until March 5, 1992, when identified by the inspector. This is a violation (VIO 50-219/92-04-01).

The walkdown inspection of core spray system I resulted in no other notable findings. Core spray system I was found to be in a condition of standby readiness, capable of performing its intended function, notwithstanding the discrepancies found on the electrical checkoff list.

1.3 "C" Emergency Bus Undervoltage Relay

On March 12, 1992, at 10:33 a.m., the control and indicating power fuse for the degraded voltage protection undervoltage (UV) relays failed for the "C" emergency bus. The failure was identified by a continuous firewatch stationed in the 4160 V switch gear room. The firewatch noted that there was arcing from the breaker panel and that the nine relay indicating lights (three for each relay) went out. This was quickly reported to the control room. The group operating supervisor (GOS) and a control room operator (CRO) were sent to the switch gear room to investigate the report. The licensee believed that only the indicating light power supply was affected. However, based on further review of the system drawings, the licensee determined, at 12:05 p.m., that the blown fuse rendered all three relays inoperable. In response the relays being inoperable, GPUN initiated a plant shutdown at 12:20 p.m.

Technical specification (TS) table 3.1-1, item N, required that if one relay were inoperable, the relay was required to be placed in the tripped condition within one hour. Initially the licensee interpreted this as requiring all the relays be placed in the tripped condition. This would have resulted in the "C" emergency bus, one of two emergency busses, being removed from service. Based on this interpretation, GPUN requested a temporary waiver of compliance from TS table 3.1-1, item N, to prevent degrading the availability of the safety systems associated with the "C" emergency bus while the shutdown and repair efforts were underway. The waiver was granted subject to a review of the request by the licensee's Plant Review Group (PRG).

The PRG reviewed the TS requirements specified in table 3.1-1, item N. By 3:00 p.m., the PRG had determined that with all three UV relays inoperable the requirement to place them in a tripped condition was not applicable and that compliance with the action statement of TS 3.0.A was required. TS 3.0.A requires the licensee to place the plant in a cold shutdown condition within 30 hours. As noted previously, a shutdown was in progress and the licensee was in compliance with TS 3.0.A. In addition, the PRG determined that a temporary waiver of compliance was not required and retracted the request.

To restore UV relay operability, the licensee originally planned to jumper across the light socket leads; however, further evaluation determined that the best course of action was to replace the damaged light sockets, associated wiring, and relays. The inspector observed the maintenance activities and reviewed the engineering and safety evaluations prepared to support the work. Discussion of the corrective maintenance performed can be found in section 3.3 of this report.

After the maintenance had been completed, a new control and indicating power fuse was installed. The grid undervoltage relay surveillance was completed and the UV devices were declared operable. The shutdown was stopped at 10:45 p.m., on March 12, 1992, with reactor power at 59%. By 12:45 a.m., on March 13, 1992, reactor power was returned to 100%.

Later on March 13, 1992, after a quality assurance review of the job package, GPUN determined that the new fuse was not qualified for safety related applications. This required the licensee to either qualify the fuse in-place on the basis of testing of similar fuses, or to replace the fuse with a qualified fuse. Initially, the licensee planned to qualify the fuse in-place; however, they decided to install a qualified fuse since it was quicker. This required the licensee to voluntarily re-enter the action statement of TS 3.0.A at 9:42 p.m., on March 13, 1992. The fuse was replaced and testing completed by about 10:52 p.m., on March 13, 1992.

A critique on the installation of the non-qualified fuse was held on March 16, 1992, to establish the facts on this event. At the end of the inspection period the critique summary had not been completed and the inspector had not reviewed the corrective action planned by the licensee. The installation of the non-qualified fuse remains an unresolved item pending NRC review of the critique summary and review of the planned corrective actions (URI 50-219/92-04-02).

The inspector observed control room operator response during the initial phases of the reactor shutdown. Operators were well informed of the situation and the shutdown proceeded smoothly. Plant management kept the operators abreast of the status of the requested temporary waiver of compliance from TS Table 3.1-1, item N, and provided clear and concise direction on measures to be taken to ensure that the emergency bus was protected from undervoltage conditions. These instructions included requesting the load dispatcher to notify the control room of voltage instabilities on the grid, monitoring bus voltage with direction to trip tie breaker 1C from the control room on indication of degraded bus voltage, and stationing an operator in the 4160 V emergency switchboard room in direct communication with the control room to manually trip breaker 1C if directed by the control room.

The inspector attended the PRG meeting and found the discussion held was well done. The PRG determined correctly that a temporary waiver was not required and that the shutdown the licensee had already commenced was as required by TS 3.0.A.

To ensure that similar problems did not exist with the other vital 4160 V bus, GPUN performed an inspection of the breakers in the 1D bus. The inspection consisted of measuring the current for each socket, checking part numbers, and a visual inspection of all sockets for signs of over heating and loose connections. Based on this inspection, no evidence of damage was found similar to the 1C bus breakers and none of the sockets needed replacement.

During the root cause analysis of the event, plant engineering identified that the socket internal leads are close together, without any physical barrier between them. This allows the leads to be pushed closer together while screwing the light bulbs into the socket. This action could cause the internal socket leads to develop an arc. The arc can draw high current, until the system fuse blows. With the existing UV relay circuit configuration, the common lead for each light socket is daisy chained from light socket to light socket. The failure of one light socket renders all three relays inoperable when the control and indicating power fuse blows.

The inspector discussed the evaluation with plant engineering and observed the condition of the four removed sockets. All four sockets were charred and burned. The one that had resulted in the blowing the control and indicating power fuse had melted insulation. The other replaced sockets showed signs of past high temperature damage. The licensee had determined that the other sockets had been damaged when the light bulb internal leads shorted together, drawing excessive current. This type of failure had occurred before at Oyster Creek and also recently at Indian Point 3, operated by the New York Power Authority (NYPA) (See NRC Inspection Report Number 50-286/92-03). While blowing of the control and indicating power fuse has not been attributed to the internal shorting of the light bulbs at Oyster Creek, this failure mechanism had resulted in similar fuses being blown at Indian Point 3.

The engineering staff has been in contact with the engineering personnel at Indian Point 3. The licensee indicated that the UV relay circuit configuration and the type of indicating lights used in the circuit were being evaluated to determine the appropriate method to prevent this failure in the future.

The inspectors concluded that the licensee had responded promptly to the initiating event. Review of the event by the PRG was well done. The maintenance performed in response to the event was good with the exception of the installation of a non-qualified fuse during the initial repairs. Engineering support in evaluating the root cause of the event was well done. Quality assurance review of the job package was responsible for identifying the installation of the non-qualified fuse. The licensee's request for a temporary waiver of compliance, while later found not required, was appropriate based on the short time specified in TS table 3.1-1, item N, and the desire not to render the 1C bus inoperable. Continued review of the modifications planned to the control and indicating power circuit to prevent future failures will be performed during routine inspection activities.

1.4 Equipment Operator Tours

During the inspection period, the inspectors accompanied several equipment operators (EOs) as they completed the reactor building and intake tour logsheets. The focus of this effort was to assess the EOs methods for completing the tours and their logkeeping practices. In addition, the guidance provided to the EOs by operations management was discussed with both the EOs and their immediate supervisors, the Group Operating Supervisors (GOSs). The inspection was performed in response to the identification of tour and logkeeping weaknesses for which the licensee was performing an internal investigation.

The inspectors accompanied EOs as they toured the reactor building, during the second tour on the 12 to 8 shift on March 20, 1992, and the first tour on the 8 to 4 shift on March 26, 1992. The reactor building tour consists of a walkdown of each elevation of the reactor building, the cable spreading room, and the 460 V switchgear room. The inspectors noted that the EOs were knowledgeable of the conditions in the plant, understood the requirements for recording data required by the tour sheet, and of the need to report unusual or deficient conditions to the GOS.

On March 25, 1992, the inspector accompanied an EO during the first tour of the intake structure for the 8 to 4 shift and on March 27, 1992, the inspector went on the second intake tour of the 12 to 8 shift. The intake tour consists of a walkdown of the A/B battery room, the recirculation pump MG set room, the nitrogen storage tank, the emergency diesel generators, the station transformers, the condensate transfer building, the chlorination building, the breathing air compressors, the intake area, the dilution pump area, the redundant fire pump structure the hydrogen tanks, and the fire pond area. During the tour the inspectors noted that the EOs had a good knowledge of the conditions of the areas that they toured, knew the requirements for completing the intake logs, and were responsive to identified problems.

After discussing tour expectations with the EOs, the inspector found that the detail of the tour was different for each EO. Some EOs performed very detailed tours, beyond what was described in the tour sheet, because they were not sure exactly what was expected. Others performed the tours as described on the tour sheets, only taking the logs and making the observations required by tour sheet. The inspector also discussed oversight of EO activities with the GOS. Oversight by the GOSs varied from randomly accompanying EOs on their tours to random spot checks throughout the shift. Management expectations had not always been clearly provided to the EOs on the level of detail necessary to adequately perform their tours or to the GOSs on what level of oversight they should provide. Even with the lack of management expectations provided to the EOs, the tours observed by the inspectors were generally very well conducted and the operators were knowledgeable of the minimum requirements for the completion of their tours.

Recently, GPUN has issued operation standards relating to the conduct of tours and log keeping practices. The inspector reviewed these standards and found that they contained general information on expected practices and methods for accomplishing tours and completing logs. Detailed guidance on EO activities essentially remains at the discretion of the GOS on shift. GPUN is developing guidance for the GOSs on the level of EO oversight they should provide. Operations management had directed the GOSs to accompany all of the EOs during at least one tour after the initial concerns were identified to ensure that any problems or weaknesses with the tours were identified and corrected.

The inspector concluded that the licensee's actions to strengthen the oversight of EO activities and the GOSs providing guidance to the EOs while on tours with them was a positive effort. No tour or log keeping weaknesses were identified by the inspectors in their observations of EO activities. GPUN had not yet completed the investigation into the weaknesses identified with EO tours and log keeping practices. When that investigation is complete, the NRC plans to review the investigation report to determine what additional NRC action will be required to ensure this issue has been addressed.

1.5 Reactor Building Ventilation Trip and Deluge System Initiation

On March 20, 1992, at about 12:05 p.m., the reactor building ventilation system tripped due to an unknown cause. Initial attempts to restart the ventilation system failed. The operators then manually initiated standby gas treatment system (SGTS) I to ensure secondary containment integrity was maintained. At almost the same time that SGTS I was being started, control room indication showed that the reactor building deluge system had initiated. The group operating supervisor (GOS) and a control room operator (CRO) were sent into the reactor building to determine the need for the deluge system to be operating. No conditions requiring the deluge system were identified by the GOS or the CRO. The deluge system was then secured.

The licensee determined that the most probable cause of the deluge system initiation was the buildup of diesel exhaust in the reactor building ventilation system ductwork when the ventilation system tripped. The sand bed removal project has a diesel driven vacuum located inside the reactor building truck bay. Exhaust from this diesel is routed into the reactor building ventilation exhaust ductwork and discharged to the stack. The exhaust filled the ductwork and was forced out into the reactor building, setting off one of the fire detectors on the 51 ft elevation of the reactor building. This caused deluge system number 6 to initiate. Deluge system number 6 provides a spray in the reactor water cleanup (RWCU) pump area and a water curtain around the equipment access opening located on the west side of the reactor building. The sand bed removal diesel was secured about 4 minutes after initiation of SGTS I. The deluge system was in operation for about 10 minutes.

Firewater system header pressure remained above about 82 psig and the fire diesels did not start. Initially, one of the firewater system pond pumps was running; however, the CROs started a second pond pump to maintain firewater system pressure above the point that would have started a fire diesel. Deluge system flow was limited to between 100 and 200 gpm. As a result, between 1000 and 2000 gallons of water was sprayed into the reactor building.

The inspector observed control room activities as the recovery was underway. Restoration of normal reactor building ventilation was delayed due to the manual initiation of SGTS I and closure of the reactor building ventilation supply dampers. This led to some confusion when attempts were made to reset the reactor building ventilation system trips because the fans trip when the supply dampers close. Reactor building ventilation was restarted and SGTS I secured at about 12:50 p.m. using normal plant procedures. The group shift supervisor (GSS) used the available personnel to respond to the event in a very effective manner. Control room response was effectively coordinated.

In addition, the inspector toured the 23 ft and 51 ft elevations of the reactor building. Area cleanups were well underway within 30 minutes of the deluge system initiation and the affected areas were restored to pre-event conditions in about 3 hours. No equipment damage was evident to the inspector. The only components that had evidence of being sprayed were the cable trays located just below the sprinkler heads and a small area on the reactor building closed cooling water (RBCCW) system heat exchangers.

In conjunction with the cleanup efforts, an electrical engineer and several electricians examined the affected cable trays to determine the need to inspect conduit junction boxes for water intrusion. No evidence of water intrusion was noted and there was no need to open any junction boxes during this walkdown.

The cause of the reactor building ventilation system trip is still uncertain. Based on the information available from March 20, 1992, the licensee felt that a definite root cause may not be identified. However, the licensee felt that the preliminary evidence indicates that a faulty pressure switch used to measure the differential pressure between the interior and exterior of the reactor building may have cause the trip. These switches (DPS-101L and R), located on the 119 ft elevation, are used to sense a high building pressure and will trip the ventilation system. No alarm function is provided with these switches. A separate pressure switch provides the alarm function. Before, during, and after the event there was no indication of a high pressure condition in the reactor building. The licensee had planned to replace DPS-101L and R in the near future; however, with this recent trip the replacement was performed on March 21, 1992.

Since the sand bed diesel vacuum had run about four minutes while SGTS I was in service, GPUN conducted an evaluation of the effect of the diesel exhaust on the system charcoal beds. This review questioned the ability of the charcoal beds to function properly. Thus, the licensee declared SGTS I inoperable and entered a seven day technical specification limiting condition of operation action statement. Test canisters were removed from the system and sent to an offsite laboratory for analysis. The sample results indicated that the charcoal bed was still 99.81% efficient. On March 21, 1992, the licensee exited the TS action statement and declared SGTS I operable. Based on the test canister results a new analysis was performed that supports operability of the SGTS with diesel operation for about 25 minutes without degradation.

GPUN secured sand bed removal operations while evaluating means to continue diesel driven vacuum operation without another event of this nature. Sand bed removal operations were recommenced March 23, 1992. After reviewing the methods used during the initial phases of sand bed removal the licensee reinstated the earlier methods. This consisted of isolating the deluge systems for the 23 ft and 51 ft elevations and stationing continuous firewatches while sand bed removal was in progress.

The inspector concluded that the licensee had responded appropriately to this event. Cleanup efforts were performed well. Troubleshooting of the removed pressure switches was still being performed at the end of the inspection period and will be reviewed on a routine basis. GPUN's action to secure sand bed removal until reviewing the available options was appropriate. Establishing continuous firewatches and securing the deluge systems will allow the licensee to complete the current phase of sand bed removal with only a minor impact on plant operations. The inspector had no further concerns.

1.6 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. House keeping efforts continue to keep the reactor building clean. Control room operators responded well to the several challenges encountered during the inspection period.

2.0 RADIOLOGICAL CONTROLS (71707)

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 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 (62703,61726,49001)

3.1 Erosion/Corrosion Monitoring Program

Background

In recent years, several nuclear power plants have reported severe incidents of pipe wall thinning and failures in high-energy carbon steel piping. The catastrophic piping failures at the Surry Nuclear Power Station in 1986, Millstone Unit 3 in 1990, and Millstone Unit 2 in 1991 were due to erosion/corrosion (E/C) of pressure boundary piping and components.

After the Surry feedwater pipe rupture event, which resulted in fatal injuries to four workers, the nuclear industry and the NRC took initiatives to address the pipe wall thinning E/C issue in high-energy single-phase carbon steel piping systems. The NRC initiated generic communications, NRC Bulletins 87-01 and Generic Letter (GL) 89-08, in response the E/C failures to ensure that adequate guidance was provided to licensees for corrective actions and other activities regarding repair and replacement of degraded piping and components. In 1987, Nuclear Utility Management and Resource Council (NUMARC), in conjunction with Electric Power Research Institute (EPRI), developed guidelines for inspection and repair of single-phase piping. The NRC found the guidelines acceptable and published the guidelines as Appendix A of NUREG-1344, "Erosion/Corrosion - Induced Pipe Wall Thinning in U.S. Nuclear Power Plants."

Purpose

The purpose of this inspection was to review the actions of General Public Utilities Nuclear (GPUN) in the area of erosion/corrosion control. In addition, the inspection was performed to verify that a long-term E/C monitoring program for high energy two-phase as well as single-phase piping systems had been developed in accordance with NRC guidance contained in, GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and the licensee commitments to, NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants."

Inspection Criteria

The inspection of GPUN's erosion/corrosion program was based on the above-identified NRC generic communications and industry guidelines established in NUREG-1344. The acceptance criteria used for the piping and components wall thinning evaluations at Oyster Creek is based on the design and fabrication code requirements of ANSI/ASME Standard B31.1, "Power Piping," 1983 Edition.

Pipe Wall-Thinning Monitoring Program at Oyster Creek

Pipe wall thinning due to erosion/corrosion was first identified at Oyster Creek in June 1978, when the "C" feedwater pump discharge 8x14 inch reducer developed a through-wall crack during power operations. General Physics investigation report GP-R-455 concluded that the failure occurred due to cavitational type erosion. The report recommended that additional E/C inspections be performed on components from other susceptible lower priority systems.

During the 1978 outage, 18 components were inspected from priority groups 1 and 2. The inspections resulted in replacement of the other 8x14 inch reducers on the discharge piping of the "A" and "B" feedwater pumps. The inspection locations were selected on the basis of maintenance records, past experience, and by using local flow rates at various components.

The initial Oyster Creek erosion/corrosion monitoring program was assessed by the NRC in July 1988. Results of the inspection are documented in NUREG-1344. The NRC found that the licensee had not formalized implementation procedures and administrative controls for their E/C monitoring program.

The E/C monitoring program has evolved since the NRC inspection in July 1988. GPUN continues to enhance their E/C program by evaluating and incorporating industry experience into their pipe wall thinning specification, SP-1302-12-237, "Erosion/ Corrosion Program," Rev. 4, which implements Oyster Creek's guidelines of Technical Data Report TDR-861, "OCNGS & TMI-1 E/C Inspection program for Steam, Two-Phase and Liquid Systems," Rev. 1. TDR-861 outlines the licensee's programmatic approach to E/C inspections and covers the program organization, inspection techniques, inspection location selections, and repair/replacement guidelines.

GPUN is currently changing their E/C program. The old program was based on component prioritization of inspection locations on engineering judgment, plant experience, and their own in-house computer program, without performing actual wall thinning calculations. GPUN conducted a study comparing the EPRI CHEC and CHECMATE programs with their own in-house generated computer program for one partial system to determine which program best identifies components susceptible to E/C. Results of the study determined that the EPRI CHECK series programs were superior to the GPUN program. Specifically, components that were ranked low by GPUN's program but had to be replaced due to E/C were ranked high by the CHEC series programs. Based on the evaluation of the results, GPUN is currently utilizing the EPRI CHEC/CHECMATE programs as the basis of its E/C program. GPUN started using the CHEC/CHECMATE programs after the 13R outage (summer 1991) in conjunction with inspection data, engineering judgment, and plant experiences to prioritize future susceptible locations for inspection.

GPUN intends to incorporate the various E/C monitoring implementation documents, such as TDR-861 and specification SP-1302-12-237, into a formal E/C program description by summer 1992. GPUN's GL-89-08 response committed to having the E/C program formalized in time to support the 14R outage which is currently scheduled for January 1993. The commitment date appears to be attainable.

E/C inspection results are currently tracked by TDR-943, "Pipe Erosion/Corrosion Inspections," Rev. 1. Review of the procedure indicates that a total of 259 E/C inspections have been performed at Oyster Creek between 1978 and 13R. All of the specific components reported as having experienced pipe wall thinning due to E/C which required repairs or replacement are documented in Attachment A to this report. Future E/C inspection results will be permanently managed and tracked by computer database program CHEC-NDE.

Affected Systems and Components

The licensee's response to NRC Bulletin 87-01, dated September 21, 1987, identified the systems within the scope of the Oyster Creek E/C pipe wall thinning monitoring program. Currently, the systems encompassed in the Oyster Creek E/C program are the following systems:

- Main Steam (411)
- Extraction Steam (413)
- Feedwater (4[illegible])
- Heater Drains (431)
- Reheat Steam (412)
- Condensate (421)

Comparing the systems listed in the licensee's response letter to the current list indicates that some of the systems identified in the bulletin response letter have been eliminated from the current scope of the Oyster Creek E/C monitoring program. Certain systems were excluded from the E/C program at Oyster Creek based temperature, piping material, fluid velocities, or other criteria. Based on GL-89-08, NRC Bulletin 87-01, NUREG-1344, and Safety Analysis Report, the inspector determined that the licensee's E/C program includes all the appropriate high energy piping and the most susceptible balance of plant piping systems.

Inspection Findings

The overall program responsibility for management of the erosion/corrosion monitoring program is different than the organization specified in the E/C specification SP-1302-12-237, Rev. 4. The plant material group which had been responsible for management of the Oyster Creek E/C program has been replaced by the technical functions corporate organization. The licensee has stated that when the formal E/C program description is issued, the assignment of responsibility will reflect the current practice.

There are currently four open Field Change Requests (FCRs) that have been initiated against the E/C specification SP 1302-12-237. The open FCRs are FCR-072438, FCR-072440, FCR-072450, and FCR-072451 which were originated due to review of industry experience information. The licensee intends to accomplish these additional E/C inspections as described in these FCRs during the first available outage of opportunity. Review of the four FCRs revealed that none required immediate inspection.

The requirement in TDR-861 to have inspection data reports issued within six months of the completion of a refueling outage was not satisfied for the last 13R outage. The inspection data report TDR-943, Revision 1, was not approved until March 1992, which is approximately eight months since the 13R outage ended in June 1991.

Overall Erosion/Corrosion Program Assessment

Based on review of the licensee's implemented E/C program guidance documents, the inspector determined that the licensee's E/C program has improved substantially since the earlier NRC inspection in 1988. It has progressed from a program which basically selected susceptible inspection locations based on engineering judgment to a program which is capable of predicting, identifying, and prioritizing inspection locations based on wear rates, inspection data, and the CHEC/CHECMATE computer programs.

3.2 Surveillance Observation

The inspectors observed selected surveillance tests to determine whether properly approved procedures were in use, appropriate approval was obtained and prerequisites satisfied prior to beginning the test, test instrumentation was properly calibrated and used, radiological practices were adequate, technical specifications were satisfied, and personnel performing the tests were qualified and knowledgeable about the test procedure. The following surveillance test activities was observed.

> 636.4.003, revision 41, "Diesel Generator Load Test," performed March 23, 1992, on Diesel Generator No. 2

During the initial start attempt of emergency diesel generator (EDG) No. 2, a sequence fault occurred when the output breaker failed to close within 60 seconds as required by the automatic synchronization and loading circuitry. When tested, the EDGs are automatically synchronized to allow diesel loading. This function is bypassed during an emergency start of the EDGs. The licensee backed out of the surveillance test and informed engineering of the problem. Engineering requested that the EDG be started again so observation of automatic synchronization circuitry could be made. During the second start attempt, EDG No. 2 started and loaded as designed. EDG No. 2

automatically synchronized to the grid in about 26 seconds. The licensee initiated a deviation report to document the failure and plant engineering performed an evaluation of the event and determined that the most likely cause was the frequency ramping function of the automatic synchronization circuitry slightly out of tolerance. When practical, the licensee will adjust the frequency ramping function setpoints.

The inspector observed the performance of the test from the control room, reviewed the engineering evaluation, and discussed the initial start attempt with the licensee. The inspector concluded that the licensee had responded to the initial failure in the appropriate manner, the engineering evaluation adequately considered other possible root causes for the failure, and that the operability of EDG No. 2 was not in question.

3.3 Maintenance Observation

The inspector observed the performance of job order number (JO #) 37338 to repair/replace the temperature recorder for the isolation condenser and electrical-mechanical relief valves (EMRVs). The inspector reviewed the work package and determined that required approvals had been obtained and that the work was being performed in accordance with the procedure. When questioned, the technicians were knowledgeable of the procedure requirements and scope of the work. Overall, the work was well controlled and conducted.

During the March 12, 1992, "C" Bus breaker undervoltage indicating light failure (see section 1.2), the inspector observed the removal and replacement of four of the nine indicating light sockets. Two of the sockets were replaced due to damage and two were replaced due to questionable resistance readings and carbon buildup in the socket. Initially this maintenance was being controlled as a temporary variation (TV) that was going to jumper out the light sockets. However, the licensee decided to issue an immediate maintenance procedure to investigate and repair as necessary the indicating light circuit. This immediate maintenance procedure superseded the TV. The inspector reviewed the immediate maintenance package and found it to be properly prepared, reviewed, provided adequate guidance on the maintenance to be performed, and specified appropriate post maintenance testing to verify UV operability. Adequate controls were in place and the work was observed to be well conducted. The licensee's decision to replace the damaged indicating sockets was appropriate.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707,40500)

4.1 Concrete Leachate Effects on Reactor Building Components

During a routine tour of the reactor building, the inspector noted the buildup of material on the core spray system II piping (stainless steel) adjacent to the core spray parallel discharge valves and on the refuel cavity cooling piping (aluminum) located on the 75 ft elevation. The source of this buildup was material that had leached from the ceiling as water from the equipment storage pool migrated through concrete. Historically, when the equipment storage pool was filled with water during an outage, small cracks developed in the steel liner, allowing water to reach the concrete floor. The equipment storage pool is located directly above the area where the buildup of material has been observed. To prevent the leakage of water from the equipment storage pool, the licensee has coated the pool with a strippable coating during the last several refueling outages. This has been effective in stopping the leakage.

The inspector questioned the licensee on the effect this concrete leachate had on the stainless steel core spray piping and on the aluminum fuel pool cooling piping. An analysis of the effects on carbon steel piping had already been completed by the licensee. This was done in response to a concern for the re-enforcing steel within the concrete when a rust-like substance was observed in hairline cracks in the ceiling of the 75 ft elevation of the reactor building. This occurrence was documented in material non-conformance report (MNCR) 86-870, dated October 21, 1986. No analysis existed for the effect of this material on the core spray or refuel cavity cooling piping.

The licensee reviewed the previous sample results that they had obtained in 1986 and determined the consequences to the stainless steel and aluminum piping was minimal. However, they also determined that a new sample and updated analysis would be required to ensure the composition of the concrete leachate had not changed and that there continued to be no adverse effect to the affected piping. Two additional samples were taken and the analysis completed on March 2, 1992. The analysis by Technical Functions found that the material contained in the leachate was compatible with the piping materials. Thus, concrete leachate would have no adverse affect on the core spray or fuel pool cooling piping. In addition, the licensee determined that the removal of this material from the piping could be potentially more damaging to the piping than leaving it in place. Therefore, the licensee has decided to leave the leachate in place.

The inspector reviewed the 1986 MNCR; 1986 sample analysis; March 2, 1992 sample analysis; and discussed this issue with licensee personnel. The inspector concluded that the licensee had adequately analyzed the affects of the concrete leachate on the core spray and refuel cavity cooling piping and had no additional questions.

5.0 EMERGENCY PREPAREDNESS (71707)

5.1 Quarterly Drill

The inspector observed activities in the technical support center (TSC) during the quarterly emergency preparedness drill conducted on March 11, 1992. This drill was primarily for a response team that had not drilled in about a year and to identify equipment degradation, personnel weaknesses, and procedure difficulties. While observing the response in the TSC, the inspector did not note any significant deficiencies with player response. The drill coordinators and observers were providing the players with feedback to improve their performance. The inspector concluded the drill was adequate in providing the licensee the opportunity to refresh the response capabilities of this team of players in the TSC.

5.2 Technical Support Center Ventilation

In December 1991, GPUN identified several deficiencies with the ventilation system in the technical support center (TSC). The deficiencies were identified by testing the TSC ventilation system in response to a July 1991 Quality Deficiency Report (QDR) number 91-055. This QDR documented that testing of the TSC ventilation system had not been accomplished at the 18 month frequency specified in Standard Review Plan (SRP) 6.4, "Control Room Habitability System." A preliminary NRC review conducted in December 1991, and documented in NRC Inspection Report Number 50-219/91-37, resulted in an unresolved item (UNR 50-219/91-37-01) related to the maintenance of the TSC ventilation system and on how the licensee was implementing the requirements of NUREG 0737, "Clarification of TMI Action Plan Items."

In response to the inspector's questions, GPUN reviewed the licensing basis for the TSC ventilation system. The licensee determined that the current licensing basis for the TSC ventilation system was provided to the NRC in correspondence dated April 1, 1982, and April 15, 1983. In addition, the inspector determined that these letters were the subject of a June 12, 1984, Confirmatory Order. The correspondence and the Confirmatory Order required the TSC ventilation system to meet the guidance contained in NUREG 0737, SRP 6.4, and portions of General Design Criteria (GDC) 19, "Control Room " of Appendix A to 10 CFR Part 50.

GPUN reviewed the design characteristics of the TSC ventilation system to the requirements specified in SRP 6.4 and GDC 19. Based on this comparison, the TSC ventilation system was designed to meet the applicable requirements; however, SRP 6.4 specifies that the ventilation system shall be tested on an 18 month frequency. Specifically, the TSC ventilation system was to be tested to verify that system makeup was $\pm$ 10% of the design value, and that the TSC can be pressurized to at least $^1/_8$ inch water gage while making up at the designed rate. This testing has not been accomplished.

In addition, no maintenance had been performed on the TSC ventilation system until December 1991. Section 50.47(b)(8) to 10 CFR Part 50 requires adequate emergency response facilities to be available and maintained.

The licensee has initiated some corrective and compensatory actions to address the deficiencies identified in December 1991. The charcoal beds that had failed the leak test were replaced, the bypass damper that had excessive leakage was repaired, the outside air supply damper was re-adjusted to ensure the design makeup flow of 790 scfm was maintained, and troubleshooting of the system demonstrated the ability of the ventilation system to maintain a positive 1/8 inch water gage. Retesting of the ventilation system was postponed due to the need to replace the test canisters for the charcoal bed. GPUN also recalculated the dose estimates to personnel in the TSC based on a filtration system efficiency of 95% instead of the previous analysis that had used 99% efficiency and installed an automatic, alarming Iodine sampler in the TSC.

The inspector has observed the operation of the TSC ventilation system and noted that the actual TSC pressure was 0.150 inches water gage; walked down the TSC ventilation system; discussed corrective actions with the licensee; reviewed the April 1, 1982, and April 15, 1983, GPUN docketed correspondence; reviewed the June 12, 1984, Confirmatory Order; reviewed the licensee's comparison of TSC ventilation system design information to SRP 6.4 and GDC 19 requirements; reviewed the re-analysis of the dose estimates; and discussed the lack of maintenance and testing of the TSC ventilation system.

Based on review of this issue in December 1991 and during this inspection period, the inspector concluded that the ability of the TSC to function as an emergency response facility was not significantly hindered by the deficiencies identified in December 1991. However, GPUN's failure to perform the testing required by SRP 6.4 as required by the June 12, 1984, Confirmatory Order, and the lack of system maintenance until December 1991, as required by 10 CFR 50.47(b)(8) is an apparent violation of NRC requirements.

6.0 OBSERVATION OF PHYSICAL 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 that 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 REVIEW OF PREVIOUSLY OPENED ITEMS (92701,92702)

(Closed) Unresolved Item 50-219/90-23-08. This item was on the performance of maintenance management inspection of work areas for the storage of QA material. In response to inspector's questioning on how the performance of these inspection was being documented, the licensee has issued quarterly preventive maintenance (PMs) procedures to document and record the completion of these inspections. The inspector reviewed the PMs for the electrical (job order number (JO #) 36873, performed March 10, 1992), mechanical (JO # 36906 and 36907, performed February 25 and March 4, 1992), and instrument and control (JO # 36750, performed February 27, 1992) maintenance organizations. In addition, the inspector discussed the performance of these inspections with the respective area superintendents. These inspections have been performed on a bi-weekly basis to allow the workers to become familiar with the requirements for storing QA material. After the initial familiarization phase is complete, the frequency will be gradually changed to a quarterly frequency.

The inspector did not have any other questions. This item is closed.

8.0 INSPECTION HOURS SUMMARY

The inspection consisted of normal, backshift and deep backshift inspection; 20.8 of the direct inspection hours were performed during backshift periods, and 9.2 of the hours were deep backshift hours.

9.0 EXIT MEETINGS AND UNRESOLVED ITEMS (40500,71707)

9.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on March 26, 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.

9.2 Attendance at Management Meetings Conducted by Other NRC Inspectors

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

March 27, 1992	Report No. 50-219/92-06 (Radiological Controls)

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

9.3 Unresolved Items

Unresolved items are matters for which more information is required to ascertain whether they are acceptable, violations or deviations. Unresolved items are discussed in sections 5.2 and 7.0 of this report.

gradually changed to a quarterly frequency.

The inspector did not have any other questions. This item is closed.

8.0 INSPECTION HOURS SUMMARY

The inspection consisted of normal, backshift and deep backshift inspection; 20.8 of the direct inspection hours were performed during backshift periods, and 9.2 of the hours were deep backshift hours.

9.0 EXIT MEETINGS AND UNRESOLVED ITEMS (40500,71707)

9.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on March 26, 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.

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9.3 Unresolved Items

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ATTACHMENT A

Oyster Creek Erosion/Corrosion Failures

CHECMATE COMPONENT	INSPECTION ID	REPLACEMENT OUTAGE	MNCR	MATERIAL	SYSTEM	NOTES
O-FWRA-E01		12U	90-0154	A106 Gr C	Feedwater	
O-FWRA-E02		12U	90-0160	A106 Gr C	Feedwater	
O-FWRA-E02		12U	90-0175	A106 Gr C	Feedwater	
O-FWRB-P06A	1A (1978)	Pre-1978		A106 Gr C (per Line Spec)	Feedwater	Per GP-R-455, pipe wall failure occurred D/S of mult bkdn orifice on the 4" min flow line from B feedwater pump
O-RF2A-R1	422-2107-R6 (12R), R3 (13R)	78, 12R, 13R	91-048	Upgrade 13R	Feedwater	This component was replaced in 1978. Repaired in 12R
O-RF2A-RE10	422-2107-R7	10R		Repaired	Feedwater	Repaired per TDR-943
O-RF2B-R1	422-2107-R5	1978, 12R	880393	A234WP22	Feedwater	Replaced in 1978 Replaced at 12R w/A234GRWP22 per TDR-943
O-RF2B-R5	422-2107-R18	10R		A106 GR C	Feedwater	Replaced in 10R with Sch. 160 reducer per TDR-943
O-RF2B-RE7	422-2107-R8	10R		Repaired	Feedwater	Repaired 10R per TDR-943
O-RF2C-R1	1 (11M), 422-2107-R1 (12R)	1978, 1980, 12R	880385	A106 Gr. C (1980) A234GRWP22 (12R)	Feedwater	Repaired in 1978 Replaced in 1980 Replaced with Cr-Mo in 12R
O-RF2C-RE10	422-2107-R9	10R, 12R	880470	A106 Gr C	Feedwater	Repaired 10R per TDR-943 Repaired 12R per MNCR 880470
O-RF2HA-RE1	422-2108-001 (R6)	12R	880468	Repaired	Feedwater	Repaired in 12R per TDR-943
O-RF2HB-RE1	422-2108-002 (R3)	12R	880469	Repaired	Feedwater	Repaired 12R per TDR-943
O-RF2HC-RE1	422-2108-R2	12R	880470	Repaired	Feedwater	Repaired 12R per TDR-943
O-DR12-P18	1C (1978) 431-2112-R5 (13R)	1978		A234 Gr WP22	Heater Drain	This component had low wall in 1978 and was replaced with Sch. 120 per GP-R-455
O-DR8-E11	431-2112-R11 (12R)	11R	See TDR-943	A106 Gr B	Heater Drain	
O-FS-12	412-2100-001	12R	89-0148	Repaired	Reheat Steam	