U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	92-03
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:	January 19, 1992 - February 22, 1992
Inspectors:	M. Banerjee, Resident Inspector J. Nakoski, Resident Inspector D. Vito, Senior Resident Inspector

Approved By: W. H. Ruland 3/11/92
W. H. Ruland, Chief, Reactor Projects Section 4B — Date

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.

TABLE OF CONTENTS

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
Report No. 92-03

Plant Operations

The licensee continues to operate the plant in a safe manner. Operator response to the trip of the "B" recirculation pump was good. Difficultly with closing the "B" recirculation line suction and discharge valves resulted in the initiation of a technical specification required shutdown. Response to an engineer's concern on core spray control wire cable separation, that resulted in a one hour NRC notification, was prompt. The separation was found by GPUN to be within the licensing bases separation criteria for Oyster Creek. Operations support of testing and maintenance activities was noteworthy in that a power reduction, required to support main steam isolation valve closure testing, was continued to allow work in the condenser bay at reduced worker exposure levels.

Radiological Controls

GPUN assessment of a hot particle personnel contamination was adequate. Corrective actions for the hot particle contamination appeared appropriate. Radiological practices used during GPUN's efforts to support the New York Power Authority's outage of the FitzPatrick site by providing them with blade guides from Oyster Creek were good. Licensee response to the identification of a previously unknown access path to a locked high radiation area on the high pressure turbine was good.

Maintenance/Surveillance

Observed maintenance activities continue to be well controlled and conducted.

Engineering and Technical Support

Engineering evaluation of the thrust values for the recirculation line suction and discharge valves was not timely. Evaluation of the "B" recirculation pump trip was adequate in identifying the root cause. NRC review of the isolation condenser line break analysis report found that it addressed the appropriate spectrum of line breaks. The analysis was conducted in response to degraded isolation condenser line break sensor performance that resulted from the lack of design control of instrument sensing line pulsation dampeners (snubbers). The analysis supported the licensee's conclusions that there would be no challenge to adequate core cooling, no adverse effects on necessary reactor building equipment and that the offsite dose consequences were considerably below FSAR design basis accident calculated values. Engineering review of a preliminary safety concern of a potential passive electrical failure resulting in the isolation of both isolation condensers was adequate. GPUN determined that the safe operation of the plant was not affected by this passive failure.

Safety Assessment and Quality Verification

LERs reviewed were found adequate. GPUN's response in developing an improved main steam isolation valve (MSIV) preventive maintenance program was thorough and consistent with industry methods. GPUN's MSIV preventive maintenance program was found adequate in addressing MSIV leakage concerns identified in Systematic Evaluation Program (SEP) Topic XV-19. A GPUN QA audit of the environmental qualification (EQ) program in response to NRC concerns was adequate with the exception that the audit conclusions were based, in part, on the lack of NRC inspection findings in this area. Additional improvements in the availability of EQ component information was still being developed by the licensee.

DETAILS

1.0 OPERATIONS (71707,93702)

1.1 Operations Summary

From the beginning of the inspection period (January 19, 1992) until January 26, 1992, the unit was operated at about 99% power. Output was limited due to a recurring leak on the level column of the second stage reheater drain tank that required the reheater to be removed from service. On January 26, 1992, at 1:16 p.m., the "B" recirculation pump tripped. While attempting to isolate the "B" recirculation line, both the pump suction and discharge valves failed to close on the initial attempts. The licensee initiated a technical specification (TS) required shutdown. The shutdown was terminated at 1:48 p.m., after the discharge valve had been closed. See paragraphs 1.2 and 4.1 for discussions on the failure of the recirculation valves to close and the cause of the "B" recirculation pump trip, respectively. Power was stabilized at about 85% following the pump trip and as a result of the started shutdown. By 1:20 a.m. on January 27, 1992, the "B" recirculation pump was returned to service and reactor power was increased back to 99%.

Reactor power remained at 99% until January 31, 1992. Power was reduced at 10:00 p.m. on January 31, to support main steam isolation valve (MSIV) closure testing, turbine valve tests (TVTs), and maintenance work in the condenser bay. Reactor power was decreased to about 35% for the MSIV closure testing and TVTs. After testing was completed, reactor power was limited to about 60% while maintenance was being completed to repair the leak on the second stage reheater drain tank level column. The work was completed and power was increased by early February 2, 1992. Reactor power was increased to 100% and remained there through the end of the inspection period (February 22, 1992).

1.2 Recirculation Pump Trip

On January 26, 1991, at 1:16 p.m., the control room operators received alarms indicating a trip of reactor recirculation pump "B." Following plant procedure 2000-ABN-3200.02, "Recirculation Pump Trip," Rev. 11, the operators attempted to close the pump discharge valve, but the valve did not fully close. The operators then attempted to close the pump suction valve as required by the procedure. This step was performed to prevent a reverse flow condition and the subsequent effects on average power range monitor (APRM) rod block and scram set points; however, the suction valve also did not fully close.

GPUN decided to start a reactor shutdown due to failure to close the discharge valve and place the loop in an isolated or idle condition as required by the technical specification. Following the procedure, an attempt was made to close the pump discharge valve from the valve control breaker. At 1:26 p.m., the "B" loop was placed in idle condition when the electricians succeeded in closing the discharge valve. The reactor shutdown was terminated.

After repairing the pump MG set, the "B" recirculation pump was returned to service on January 27, 1992. However, the discharge valve did not fully open after 3 1/2 minutes on the first attempt as indicated by a double position indication (both open and closed). The operators again attempted to open the valve from the control room with the valve in the double indication position and after 12 additional seconds with the control switch in the open position, the valve indicated full open.

Inspector review of operator response to the event found it appropriate. The necessary notification was made to the NRC. Recirculation loop valves have a history of difficulty in closing under similar circumstances. The inspector discussed the Limitorque motor operators (MO) sizing and torque switch settings with plant engineering. The plant engineer indicated that calculations performed to determine MO thrust requirements did not incorporate flow in the recirculation loop. Recirculation valves do not have a design basis requirement to operate under any flow or differential pressure conditions. Subsequent MOVATS signatures both for open and close operation did not show any problems. These valves have not been included in the Generic Letter 89-10 program. The licensee indicated that the required thrust values were being recalculated and any required corrective action would be determined subsequent to this calculation.

The updated FSAR (UFSAR) provides a closing time of between 2 minutes and 2 minutes 20 seconds for the recirculation loop valves. Based on discussions with the licensee, these times were developed using the manufacturer's specified valve stroking speed of 12 in. per minute. At this speed the slightly smaller discharge valves should stroke closed in 2 minutes, while the suction valves should stroke closed in 2 minutes and 20 seconds. The UFSAR also stated that the suction valves were designed to open against 50 psid differential pressure (d/p) and the discharge valves were designed to open against 100 psid. The basis for the design d/p was to reduce the size of the motor operator required and still be adequate to open the valves when reactor vessel static head and recirculation pump discharge pressure were taken into consideration. The need for larger motor operators was not considered necessary because the 2 in. bypass lines provided a means to equalized pressure across the valves.

The inspector concluded that the safety significance of the event was low, as the plant design basis loss of coolant accident (LOCA) analysis assumed an unisolated guillotine break in one of the recirculation lines and design basis requirements do not include closing under flow conditions. However, the valve design closure time was not met when the valve did not fully close on January 26, 1992. While the licensee's plan to recalculate the design basis thrust setpoint was appropriate, based on the past performance of the valves, the re-evaluation should have been started sooner. The re-evaluation was not complete at the end of the report period.

1.3 Core Spray Control Logic Cable Separation

On February 13, 1992, GPUN made a one-hour notification to the NRC based on the potential for the plant being outside the design bases. The concern involved the core spray control logic cabling for both trains running in the a cable tray with the same cable tray number. An engineer, reviewing the core spray system configuration while developing an upcoming core spray modification, initially identified the concern after reviewing the cable routing information for these cables.

The licensee started a review of the core spray control logic cable routing and the separation criteria requirements based on the system design bases and regulatory commitments. The licensee determined that while the control logic cables did run in the same cable tray (number 9E), the system I and system II cables, in general, were more than three feet apart. The system I cables left the tray before the system II cables entered it. The only exception was that one of the system II control cables, enclosed in a steel conduit, ran with the system I control cables.

This system II control cable (24-43) provides the manual start signal for the core spray pump NZ01C (system I pump powered from train II emergency bus) using the control switch in the control room. The automatic start function of core spray pump NZ01C would be affected by the failure of this control cable only if the cable failed in a manner that resulted in excessive current without grounding the cable. This type of failure would subsequently fail the control power fuse to the pump breaker preventing the breaker from repositioning. The failure of cable 24-43, in conjunction with the common failure of the system I control cables, still does not defeat the automatic and manual start capabilities of core spray pump NZ01B (primary system II pump). The ability of pump NZ01B to start automatically or manually ensures the core spray system will be able to fulfill its safety function.

By current separation criteria this condition would not be acceptable. However, this portion of the core spray system cabling was designed and constructed using separation criteria specified in a November 26, 1968, revision to an APED Engineering (General Electric) separation specification titled, "Oyster Creek Project Separation Practices for Safeguards Systems."

Based on the review of previous modifications to the core spray system, the licensee had determined that the separation requirements licensing bases for the affected portion of the core spray system cabling was the 1968 APED criteria. Further, the licensee believes that these criteria had previously been found acceptable to the NRC in 1976, as documented in the NRC approved Amendment No. 12 to the Oyster Creek operating license.

The inspector reviewed the 1968 separation criteria, cable tray drawings, and Amendment No. 12 documentation; observed the physical arrangement of the cable trays in the turbine building basement under the 4160 volt switch gear room; and discussed this issue with Technical Functions and GPUN Licensing personnel. Based on that review, the inspector concluded that the licensee had responded promptly to the engineer's initial concern and devoted adequate resources to walkdown the core spray system control cabling quickly to identify the magnitude of the concern. In addition, the inspector determined that the existing core spray control cabling in question was meeting the separation criteria specified in the 1968 APED document. While the separation criteria used during the design and construction of this portion of the core spray system control cables does not meet the current guidance, the inspector concluded that the configuration did not represent a significant risk to the system or unit.

The licensee's position was that the core spray system control cable configuration was within the system design and licensing bases. The engineer's concern still remains open as a licensee preliminary safety concern (PSC) pending GPUN's benefit analysis on modifying the existing cable separation. The inspectors will continue to follow this issue on a routine basis until resolution of the engineer's PSC.

1.4 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. Housekeeping efforts continue to improve. The licensee's painting efforts have improved overall plant appearance.

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.

2.1 Refuel Floor Hot Particle Contamination

On January 22, 1992, a worker was fcund to have been contaminated by a hot particle. The worker had been involved in the hydrolazing and packaging of blade guides being done on the refueling floor. A skin dose calculation was performed by the licensee, with the subsequent assignment of a skin dose of 518 mRad, well within regulatory lirnits. Analysis of the recovered particle found it to consist mainly of cobalt-60 (Co-60), with an activity of 0.08 uci (direct frisk reading of 30,000 cpm).

The licensee informed the resident staff of the occurrence. No formal report to the NRC was required. The licensee documented the occurrence in radiological incident report (RIR) No. 92-003. Adequate correcuve actions were taken by the licensee to decontaminate the affected worker and to survey the refueling floor for additional hot particles. The inspector concluded that GPUN's corrective actions reflected well on their efforts to identify and correct radiological deficiencies in a timely manner.

The inspector concluded that the licensee was respon e in addressing this incident.

2.2 Discovery of Area Requiring Locked High Radiation Area Status

On January 31, 1991, radiological surveys taken within a rarely used access hatch on the high pressure turbine (HPT) housing found a dose rate area requiring posting as a locked high radiation area. After discovery, the licensee promptly installed a latch on the HPT hatch doors and locked the access point. Key control and area posting were established shortly thereafter.

While power was reduced (35% power) on the weekend of January 31 - February 2, 1992, for MSIV closure testing, turbine valve testing and other work, a Technical Functions (TF) department engineer informed radiological controls that he needed access to the small hatch on the west side of the HPT external housing to assess the material condition of blanketing material around the HPT shell below the turbine deck. The hatch was located approximately 25 ft from the rope boundary for the high radiation area around the turbine on the turbine deck. The radiological survey revealed that there was a pipe just below a grating within the hatch area that was greater than 1R/hr at 1 foot, which required the area to be posted as a locked high radiation area following GPUN's administrative procedure 9300-ADM-4110.06, rev. 11, "Control of Locked High Radiation Areas."

The inspector interviewed the TF engineer, the director of radiological controls, and other plant personnel to determine what the need to access to this hatch had been in the past. No record of prior access or request for access was found, and none of the individuals interviewed could recall a prior need for access to this area. At higher operating power levels, access to this area is not considered due to excessive area temperatures. In this case, the TF engineer felt that he could more feasibly gain access to this area below the HPT at the lower power level.

In addition to locking and posting the HPT hatch, radiological controls surveyed the other small hatches in the raised decking areas around the low pressure turbine shells and found no dose rate areas requiring locking or additional posting. The inspector concluded that the licensee had responded to this issue appropriately.

2.3 Blade Guide Removal

The inspectors observed portions of the control rod blade guide removal effort performed during the inspection period. In response to a request from the New York Power Authority (NYPA), GPUN had agreed to ship 120 control rod blade guides in support of core offload for NYPA's FitzPatrick site.

The blade guide removal effort was effectively performed and generally well controlled from a radiological exposure standpoint. A staged process was developed to promote efficient performance of the activity while concurrently keeping with ALARA guidelines. The process involved use of the refueling bridge to transfer each blade guide to the cask drop protection area of the spent fuel pool. The blade guides were then hydrolazed while in the cask drop protection area. After hydrolazing, the blade guides were raised out of the spent fuel pool area, packaged in heavy plastic bags, and moved to a separate area on the refueling floor from which the bags were packed into a shipping container. Effective actions were taken to minimize the amount of residual water in the packaging for each blade guide by (1) drying each blade guide as it was raised from the cask drop protection area, and (2) placing absorbent paper at the bottom of the plastic packing bag to soak up any remaining moisture. Each blade guide was monitored continuously by radiological control technicians during the removal, hydrolazing, and packaging processes. Smear samples were taken and counted routinely during the process. Appropriate protective clothing and dosimetry were worn by the personnel performing and monitoring the activity.

3.0 MAINTENANCE (62703,61726)

3.1 Isolation Condenser Valve Preventive Maintenance

On February 3, 1992, the inspector observed mechanics verifying the torque on the packing glands nuts for the isolation condenser valves located on the 75 ft elevation of the reactor building. This maintenance was being performed using preventive maintenance tasks Nos. 5004M and 5005M as directed by job order No. 35145 following the January 31, 1992, cycling of the valves to obtain MOVATS current traces.

The inspector verified that the work package specified the required torque valves and that the measuring and test equipment was within calibration date. Appropriate radiological controls were applied under the direction of a radiological controls technician (RCT). When questioned by the inspector, the mechanics were knowledgeable on the tasks they were performing.

To reach the valves, the mechanics had supported a ladder against the isolation condenser lines adjacent to each valve. The job package had contained an engineering evaluation to address the use of the ladder in this manner. However, the inspector noted that on several occasions the mechanics were required to briefly climb onto the isolation condenser piping for access to the valves. The inspector discussed this issue with the licensee. The licensee stated that the isolation condenser piping was reviewed for structural adequacy based on the additional weight for the brief period the mechanics were required to be on it and that the piping was adequate. The inspector did not note any other concerns.

Based on the inspector's observations, reviews, and discussions, the torque checks performed on the isolation condenser valves was adequately controlled and conducted.

3.2 Hydrostatic Testing on New Radwaste Service Water Piping

On February 11, 1992, the inspector observed the performance of the hydrostatic testing of a portion of recently installed new radwaste (NRW) service water piping. The portion of piping was between the pump and south of check valve SW-CKV-108B. Hydrostatic testing of the rest of the NRW service water piping had previously been successfully completed.

The inspector reviewed the work package (job order No. 24842, work request No. 90372) for appropriate approval, QC witness points, and specified test pressure. While observing the test the inspector verified that the specified test pressure was obtained and that the test procedure was followed. Calibration of the test gauges was current.

Personnel involved with the hydrostatic test were familiar with and appropriately followed the test procedure. Further, the inspector concluded that the hydrostatic test of this portion of the NRW service water piping was adequately controlled and conducted.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707,40500)

4.1 Replacement of Wire on "B" Recirculation Pump Motor Generator Set

On January 26, 1992, the "B" recirculation pump tripped due to a loose connection in a 7-inch long solid copper wire from a slip ring on the generator end of the motor-generator (M-G) set to the rotor winding. The loose wire caused an open circuit between the exciter and the generator brushes, causing a loss of the excitation field to the generator. The "B" recirculation pump had previously tripped on December 26, 1991, for the same reason, i.e., due to the loosening of this soldered wire connection. At that time, the connection failure was considered a random failure, was re-soldered, and the pump was restarted.

After the January 26, 1992, pump trip, plant engineering performed a more detailed evaluation because it became apparent that simply re-soldering the connection had not resolved the problem. Engineering concluded that the re-soldered connection may have been more susceptible to subsequent failure due to the rigidity of the solid copper wire. The wire was replaced with a stranded wire supplied by General Electric. The new wire was installed, soldered, and the pump restarted on the morning of January 27, 1992.

Replacement wire was available in the warehouse because GPUN had purchased additional replacement wire after the wires had been replaced on two of the other four recirculation pump M-G sets in 1987. The 1987 wire replacements were part of a modification which involved the replacement of electrical connection parts, (including the slip ring) which had been contaminated by oil in-leakage at that time.

The licensee indicated that this wire connection will be checked on all of the recirculation pump M-G sets as part of the next refueling shutdown (14R) preventive maintenance on this equipment. This addition to the PM program on the recirculation pump M-G sets was also to be documented as part of Oyster Creek maintenance assessment departments PM program upgrade effort. The inspectors concluded that the licensee had taken adequate corrective action to resolve this issue.

4.2 Review of Isolation Condenser Line Break Analysis Report

Following a September 25, 1991, incident involving degradation of the response capabilities of the isolation condenser (IC) line break (high flow) sensors (see Inspection Report 50-219/91-32 for details), GPUN analyzed postulated IC line breaks to assess the potential consequences of the degraded equipment. GPUN provided the preliminary results of these analyses verbally to the inspectors. The inspectors based their post-event conclusions on these verbal discussions. GPUN committed to provide the final report documenting these analyses to the resident inspectors when available.

The inspectors reviewed the licensee's final report (Topical Report No. 85, Isolation Condenser Isolation Valve Timing Requirements, dated January 24, 1992) to determine whether the prior discussions were appropriately documented and conclusions were adequately supported. Postulated IC line break analyses were performed to evaluate thermal-hydraulic effects on the reactor and the effect on equipment in the reactor building which would be exposed to the break. The results of the equipment qualification analyses were used to determine whether flooding caused by an IC condensate line break in the reactor building could challenge the operation of equipment important to safety. Also, the results of the analyzed IC condensate line breaks were used to evaluate the consequences of a postulated ground level radioactive release from the reactor building.

The inspectors concluded that an appropriate spectrum of line breaks was analyzed to assess the effect of extended response times for the IC line break sensors and that conservative assumptions were employed. The report concluded that there would be no challenge to adequate core cooling, no adverse effects on necessary reactor building equipment, and the offsite dose consequences were considerably below FSAR design basis accident calculated values, which in themselves were considerably below 10 CFR 100 limits. The inspectors found that the report text and accompanying analysis results adequately supported these conclusions.

4.3 Isolation Condenser Pipe Break Sensor Cable

On January 30, 1992, the licensee made a one-hour notification to the NRC after a determination was made that a condition potentially outside the design basis of the plant was identified. This resulted from an ongoing review of a preliminary safety concern (PSC) initiated by the licensee on September 25, 1991. This PSC noted that a single cable (#63-361) was used in logic train A to carry signals from the line break sensors of both isolation condensers (IC). This could result in isolation of both Ics upon a worst case failure of the cable with all conductors open. This single passive electrical failure was not considered in previous system failure modes and effects analysis.

The Oyster Creek updated FSAR described the IC system as an emergency core cooling system (ECCS). During 1975, the licensee reassessed the electrical system associated with ECCS performance and verified that no single passive electrical failure would adversely affect the system compliance with 10 CFR 50.46 criteria. Correspondence with the NRC dated June 24, 1975, July 3, 1975, and December 23, 1975, reflected this. Previous single failure considerations pertained solely to active component failures. The licensee's cycle 12 core reload submitted to the NRC, however, revised the design basis LOCA analysis which had taken credit for the IC system inventory. This revised analysis assumed the ICs to be not operable. The NRC reviewed this submittal during the cycle 12 core reload and subsequently plant technical specifications were charged as documented in amendment No. 129 issued on October 31, 1988.

The latest (December 1991) FSAR update for Oyster Creek included the cycle 12 LOCA analysis assumption that credit was taken for core spray and automatic depressurization (ADS) systems but not for the IC system. The inspector noted that various accident and transient analysis in the updated FSAR assumed normal plant cooldown or decay heat removal to be performed using the IC system and the relief valves. The licensee indicated that normal actuation of the ICs was acceptable, as the fuel limits reach their maximum value at the very onset of these transient. Even in automatic, the maximum value occurs too quickly for the IC system to respond. Manual actuation of ICs is available from the control room and from the remote alternate shutdown panel. Manual actuation overrides any isolation signal present. Upon a cable failure, both ICs would isolate, unlike an actual break situation which isolates only the affected IC. The IC isolation is alarmed in the control room, and the operators could actuate ICs by opening IC valves. Oyster Creek Appendix R (fire protection) safety shutdown analysis requires manual actuation of IC "B."

The inspectors reviewed the facility description and safety analysis report (FDSAR), updated FSAR, IC system isolation logic, and the correspondence discussed previously to determine the licensing basis of the system. System operating, diagnostic and restoration, and emergency operating procedures were also reviewed. The inspectors walked down the accessible portions of the subject cable routing. Based on this review and discussions with the licensee the inspector verified the licensee's determination that a manual actuation of the IC system was adequate for safe operation of the plant. At the end of the inspection period the licensee was preparing an LER for submittal to the NRC and reviewing the PSC for final resolution. The inspector did not note any unacceptable condition. The inspector concluded that the licensee's actions in addressing the PSC were adequate.

5.0 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.

6.0 SAFETY ASSESSMENT/QUALITY ASSURANCE

6.1 In Office Review of Licensee Event Reports (LER) (IP 90712)

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
91-002, Rev. 1	Local Leak Rate Test Results in Excess of Limits due to Valve Degradation

The content of the LERS met the intent of NUREG 1022, "Licensee Event Report System," requirement. The information presented in the LER, Rev. 1, was accurate. The adequacy of the licensee's corrective action for this LER was discussed in Section 7.0 under unresolved item 50-219/91-17-01.

7.0 REVIEW OF PREVIOUSLY OPENED ITEMS (92701,92702)

(Closed) Integrated Plant Safety Assessment Report (IPSAR) Item 4.38: This item dealt with the licensee's maintenance program for main steam isolation valves (MSIVs) and its effect on the minimization of MSIV leakage. NRC staff analysis of Systematic Evaluation Program (SEP) Topic XV-19, "Loss of Coolant Accidents Resulting from the Spectrum of Postulated Pipe Breaks Within the Reactor Coolant Pressure Boundary," showed that the major contributor to calculated offsite doses was MSIV leakage. As a result, the staff concluded that the licensee should develop a preventive maintenance program aimed at minimizing MSIV leakage. Both NUREG-0822 (IPSAR), Supplement 1, dated July 1988, and NUREG-1382, "Safety Evaluation Report Related to the Full-Term Operating License for Oyster Creek Nuclear Generating

Station," dated January 1991, referred to this issue and noted that GPUN was continuing discussions with General Electric, the BWR Owners Group, and the valve manufacturers (Atwood-Morrill) in response to this issue. The inspectors assessed the current PM program for the MSIVs to determine the adequacy of the licensee's actions in response to this issue. The major facets of the MSIV PM program are noted below.

1. Ultrasonic testing (UT) is performed on the valve stems of two MSIVs each refueling outage. This commitment was made following failure of the valve stem of MSIV NS03A, the inboard MSIV on the "A" steam line on July 9, 1988. The stem failure had been caused by high cycle fatigue resulting from impact between the valve poppet assembly and the valve stem. In addition to the establishment of the stem inspection, a technical specification requirement for a daily 5% MSIV closure test was eliminated. The UTs will help predict stem flaws prior to failure.

2. When the stem UTs are done, leak testing is performed on the valve air actuator. This PM activity helps determine the condition of the internal seals.

3. Air actuator spring replacement. Air actuator springs will have been replaced on all four MSIVs by the end of the 14R refueling outage.

4. The MSIV PM program does not call for valve disassembly unless a local leak rate test (LLRT) failure is experienced. This coincides with the current vendor and owners group position that repetitive disassembly and refurbishment of MSIVs may actually contribute to repeated failures by introducing maintenance induced defects.

5. If an LLRT failure is experienced, GPUN has committed to install an improved valve poppet which self aligns to the main valve seat during closure. A continuous ring (poppet pad) around the new poppet assembly assures full contact between the guide ribs and the poppet and minimizes the possibility of misalignment with the stem. The poppet to stem clearances are also increased due to the new assembly which provides a 0.40 in. clearance fit between the assembly and the stem. The old pilot valve seat was an integral part of the stem.

   NS03A, the "A" steam line inboard MSIV, was modified in 12R after an LLRT failure. NS04A, the "A" steam line outboard MSIV, was modified in 13R after an LLRT failure.

6. A detailed internal valve inspection is performed anytime an MSIV is disassembled for maintenance. GPUN has been maintaining a GE technical representative onsite for each outage to support this effort. GPUN has also recently purchased a special measuring tool from GE for more accurate measurement of valve bore and concentricity.

7. The current PM program specifies that all four MSIVs are to be repacked every refueling outage whether or not an LLRT failure is experienced. GPUN will be reevaluating this PM in light of the site-wide valve packing replacement effort. During the modification of NS03A and NS04A, the packing was replaced with Chesterton packing, which is designed to significantly reduce packing leakoff. The "B" MSIVs still have the older chevron-angle packing. This PM may be altered based on the performance of the new valve packing material.

GPUN is also involved with the efforts of the BWR Owners Group MSIV Leakage Closure Committee. This committee is working to obtain technical specification relaxation to significantly increase allowable MSIV leakage rates and to eliminate requirements for MSIV leakage control systems. NRC review of this issue is near completion.

The inspectors concluded that the licensee had adequately responded to the MSIV leakage issue brought out in NUREG-0822, Supplement 1, and NUREG-1382, and had developed a PM program for the MSIVs which was responsive to related regulatory, vendor, and owners group issues. This item is closed.

(Closed) Violation 50-219/90-06-06. This violation dealt with the operation of the No. 2 auxiliary boiler without restriction from February 17, 1990, to March 22, 1990, after the boiler had been contaminated by a leak in the "A" radwaste evaporator. Procedure 106.2.1, "Spill Procedure," required that, if a normally non-radioactive system was contaminated, system use shall be restricted until the problem was corrected and the system decontaminated. A safety evaluation per 10 CFR 50.59 was not performed by GPUN until March 22, 1990, to evaluate continued operation of the contaminated auxiliary boiler system.

The March 22, 1990, safety evaluation concluded that the activity levels found in the No. 2 auxiliary boiler did not exceed regulatory or design basis limits. The safety evaluation and the short-term corrective actions taken by GPUN to justify continued system operation were determined to be acceptable by NRC shortly after the incident (see Inspection Report 50-219/90-07, Section 2.2, dated June 7, 1990). The issues which remained open in June 1990 were, (1) the formal proceduralization of auxiliary boiler system contamination monitoring; and, (2) the engineering evaluation and implementation of subsequent corrective actions for other systems which could be potentially contaminated.

The inspector reviewed the current procedural guidance which addresses auxiliary boiler system contamination and found that it included appropriate operating restrictions, sampling and analysis requirements, and required actions. Procedures 327, " Plant Heating Boiler," Rev. 20, and 327.2, "No. 2 Auxiliary Boiler and Support Systems Operating Procedure," Rev. 9, the current operating procedures for the No. 1 and No. 2 auxiliary boilers respectively, required that:

1. A boiler water activity sample shall be taken before the boiler is put in service.

2. Boiler water activity and surface activity levels of specified sample points shall be documented at least once per 24 hours and when the boiler is to be blown down.

3. While the boiler is in service, demineralized water makeup is monitored every four hours for excessive makeup. Boiler shutdown is required if demineralized water makeup is 10 gpm greater than normal (3-5 gpm).

4. Boiler shall be shutdown immediately if water activity is greater than 1.65×10^{-5} uci/ml.

5. Boiler shall be immediately shutdown if a specified minimum discharge canal dilution flow is not maintained (230,000 gpm - one dilution pump).

Procedure 106.6, "Conduct of Chemistry Operations," Rev. 19, controls the boiler water activity sampling schedule. Procedure 828.8, "Secondary Systems Analysis: Boiler Water," is being changed to incorporate the control limits for boiler water radioactive chemistry sampling and their relationship to the operating procedure restrictions. The maintenance of the minimum discharge canal dilution flow is addressed through the response alarm procedure for control board alarm K-7-E, "Environmental Water Monitor," which directs the isolation of the boiler if discharge canal flow is less than 230,000 gpm.

The inspector verified that there have been no problems with auxiliary boiler water activity since March 1990. Because of good plant water conductivity levels recently, boiler water activity has been progressively declining. With the low conductivity levels, Oyster Creek has been able to use the alternate liquid processing system (ALPS) more frequently instead of the "B" radwaste evaporator, minimizing the potential for auxiliary boiler system contamination. The "B" evaporator is used when conductivity levels increase, e.g., due to salt water intrusion.

The turbine building closed cooling water (TBCCW) system, reactor building closed cooling water (RBCCW) system, and the new radwaste closed cooling water (NRWCCW) system were determined to be the other systems which could be potentially contaminated. Leakage from these CCW systems into their respective heat exchangers could result in a contaminated release to the discharge canal. Safety evaluations were completed by GPUN in May 1991 which determined permissible contamination levels for these systems based upon leakage to the discharge canal and the amount of dilution. In October 1991, engineering provided proposed methods for monitoring CCW leakage rates using surge tank levels and/or makeup rates to the operations department.

RBCCW could be potentially contaminated by a number of the systems it cools (e.g., shutdown cooling heat exchangers, reactor water clean-up (RWCU), and recirculation pump seal injection). While RBCCW was not designed as a contaminated system, it is contaminated and has been for several years. On January 30, 1992, the operations department implemented several temporary procedure changes (TPCs) to provide for monitoring of RBCCW leakage. The control limits for these procedure changes were based on a radiological engineering calculation done in support of the safety evaluations. This calculation demonstrated that as long as there was at least one circulating water pump or one dilution pump running, discharge concentration would not be affected by RBCCW leakage unless the leak rate was greater than or equal to 3 gpm (continuous leak over a three-month period). TPCs were made to the circulating water pump and dilution pump operating procedures (Procedures 323 and 324, respectively) to note the requirement for pump availability. Procedure 309.2, "RBCCW System," was temporarily changed to delineate makeup monitoring requirements for assessment of system leakage. The alarm response procedure (2000-RAP-3024.01) for control room alarm C-5-C, "RBCCW Surge Tank Level Hi-Low," was also changed to alert the control room operators of RBCCW system leakage monitoring requirements should the alarm sound.

The licensee's primary means of addressing the potential contamination of the TBCCW and NRWCCW systems is through periodic chemistry sampling. This is because the potential for contamination of these systems is considerably less likely than for RBCCW. Chemistry Procedure 828.1, "Secondary Systems Analysis: Treated Waters," has been temporarily changed to address leakage monitoring considerations. Procedure 828.1 had always included activity sampling requirements. The TPC added actions to be taken if abnormal results were found.

Most of the radioactive components cooled by NRWCCW normally operate at pressures lower than NRWCCW, minimizing the potential for contamination. The exceptions are the distillate cooler and distillate sample cooler. Also, leakage of NRWCCW to the environment would be via the NRW service water system, which operates at a higher pressure than NRWCCW. TBCCW can be potentially contaminated by leakage from the condensate and feedwater sample coolers and lube oil coolers. However, the licensee acknowledged that there was a backup function of TBCCW during which more active leakage monitoring requirements (similar to those initiated for RBCCW) should be available. Specifically, TBCCW can be cross-connected to RBCCW and used as a heat sink for the augmented spent fuel cooling system. The licensee stated that a procedure change would be developed to accommodate leakage monitoring in this operating condition.

The inspector concluded that the licensee was taking appropriate actions to address this issue. This item is closed.

(Closed) Violation 50-219/91-01-02 and Unresolved Item 50-219/91-05-01. NRC review of the licensee's response to the notice of violation was described in Inspection Report 50-219/91-39. This item was left open pending inspector review of GPUN audit report S-OC-91-15 dated November 27, 1991. This audit report resulted from an investigation performed following a request by the Director, Quality Assurance, to determine the generic impact of improperly conducted or evaluated initial walkdown on the current environmental qualification (EQ) of existing host (major components that contains subcomponents, such as motor operators that contain limit switches) and common components. The focus of the inspector review of this report was at common and interface components like terminal blocks, splices, electrical connectors, and the results of this audit in terms of identifying an adequate level of confidence that the traceability of these common items was established and incorporated in the EQ program.

The audit report made the conclusion that at the end of 11R outage GPUN had established a higher level of assurance for the specific identification and location of common items. In part, this higher level of assurance resulted from a lack of NRC EQ inspection findings regarding configuration deficiencies unknown to GPUN. NRC Inspection Report 50-219/85-39 did identify the presence of Stanwick terminal blocks which were not known to GPUN. Subsequent GPUN walkdowns also identified several cable types for which qualification had not been established. The results of walkdowns conducted during the 11R outage (1986) were also used as a basis for this higher level of confidence. This audit report also indicated that a review of deviation reports (DVR), material nonconformance reports (MNCR), and preventive and corrective maintenance activities between the period of 1985 and 1991 indicated no potential EQ deficiencies were identified. The inspector found the use of NRC inspection results to provide such an assurance level to be inappropriate. This was because NRC inspections were done on a limited sample basis and NRC findings, although limited in numbers, should not be used by the licensee as a basis for establishing a higher level of assurance.

A review of a random sampling of supplemental system component evaluation worksheets (SSCEW) was performed by the licensee to determine if they could be used to identify EQ deficiencies. The licensee concluded that trained personnel, conscientiously using the SSCEW, were provided with sufficient data to identify EQ deficiencies The process for identifying, controlling, and dispositioning EQ deficiencies was found adequate by GPUN. The inspector noted that SSCEW did not address common or interface components, as the licensee was currently updating the plant database to incorporate this information. Hence, the lack of DVRs and MNCRs identifying EQ deficiencies was not unexpected, because plant personnel had not been provided with the baseline information needed to compare against the existing equipment configuration.

The plant walkdown of EQ components performed during 11R outage (1986) was the primary source of component traceability documentation, supplemented by subsequent field change notices (FCN). The inspector reviewed the results of this walkdown on a sample basis. Versus the ECCS pump motor walkdown sheets, which contained unclear splice information, these walkdown sheets were more detailed in nature and contained sketches to identify interface components. The inspector concluded that in general the 1986 walkdowns were more comprehensive and provided a greater level of assurance regarding component traceability.

The report indicated that an additional review was done to determine if any other documentation generated subsequent to the 11R walkdown tended to corroborate the walkdown information. A list was generated containing host and common components which did not have later documentation available which either corroborated or changed the walkdown information. The list contained various cables, some position switches, terminal blocks, and drywell penetrations. The documentation supporting the walkdowns came from corrective/preventive maintenance work packages or surveillances which used SSCEW to identify the components or field change notices which documented the replacement of a component. The inspector reviewed this elimination logic and the scope of this review with the licensee.

The inspector sampled a list of EQ components to determine the basis for eliminating them from requiring further evaluation for adequate EQ configuration. Also, the inspector evaluated whether plant changes were provided to the EQ group via a documented process. Based on the inspector's review, it appeared that although a substantial amount of review of maintenance and modification information in addition to the EQ files was done during the QA audit, the scope was sometimes cut back. For example, terminal blocks outside host components were not looked at in all cases. Newer components, qualified to 10 CFR 50.49, were not included. Only Division of Operating Reactor (DOR) guideline qualified components, installed before the EQ rule was in effect, were reviewed. In the audit report the licensee concluded that the 1986 (11R outage) walkdown was considered a very thorough one, that provided reasonable assurance of component traceability. The inspector concluded that the criteria used by the licensee to eliminate components from requiring additional evaluation for acceptable EQ configuration during the QA EQ audit were generally weak, such that the result of this audit were of limited value.

In their response to the notice of violation the licensee indicated that additional information was being added to the engineering data base to enhance future identification, control, and documentation related to EQ components. The Oyster Creek GMS2 computerized component database was being expanded to address common and interface components, and additional EQ and SSCEW information related to these components. The licensee plans to complete this upgrade to GMS2 by April 30, 1992, such that information to identify the qualified configuration for these components will be available. A further upgrade of the SSCEWs was being planned by the licensee for a December 30, 1992, completion. This will provide sketches to show all interfacing and common components related to the host component. This documentation will be released in hard copy format.

A more detailed review was being performed by the licensee to capture in GMS2 information related to plant modifications performed on cables. This will be completed by December 30, 1992, such that GMS2 will identify all plant cables by cable number, location, routing, application, and manufacturer information. The licensee plans to incorporate information related to EQ by December 30, 1993.

The inspector also reviewed Station Procedure 105.3, Rev. 7, "Maintenance of Oyster Creek Environmentally Qualified (EQ) Equipment." This procedure established a process to capture plant changes to EQ components performed by maintenance. A component or part replacement was required to be processed through the plant spare part engineering group such that an FCN would be generated to update EQ documents as needed.

The inspector concluded that the incomplete ECCS pump motor splice walkdown information and inadequate evaluation of this information were not reflected in the other 1986 walkdown information reviewed by the inspector. Although other available documentation was used in the EQ program to establish traceability of common interface components, the 1986 (11R outage) walkdowns constituted the primary source. The current GPUN procedures for plant modification and maintenance on EQ equipment provide an established process to capture changes to the components in the EQ program. However, the process used in the past to capture changes and component traceability information was less structured and understood by plant personnel. Information related to qualified configuration of common and interface components was not readily available. Updating of the GMS2 database with the additional information remains an area of NRC inspector focus and will be reviewed in future inspections after completion of the licensee's current effort to verify component traceability.

(Closed) Unresolved item 50-219/91-17-01. This item was left unresolved pending licensing determination of additional corrective actions for a failure to write an LER when a main steam isolation valve (MSIV) did not meet the local leak rate test (LLRT) criteria.

On February 21, 1991, testing of MSIV NS04A did not meet the LLRT acceptance criteria. A deviation report was written. During the review of this deviation report, the licensee erroneously determined that an LER was not needed because the other valve in the series met the leakage criteria and reportability depended on the condition of the entire penetration and not on a single valve. The licensee indicated that this erroneous determination partly resulted from not being familiar with a technical specification change which was issued during 12R. Technical Specification Amendment No. 132 revised the leak rate test acceptance criteria which was previously titled "corrective actions," such that the licensee did not interpret failure of a single valve to meet the leak test criteria as a condition requiring a report under 10 CFR 50.73 (a) (2) (i) (B).

A deviation report was initiated on June 7, 1991, to review the root cause and determine needed corrective action. A memorandum was issued by the plant engineer to plant operations and engineering personnel involved in reviewing leak rate test results. This memorandum explained how technical specification acceptance criteria were to be applied to the leak rate monitor readings to determine reportability. A subsequent revision to Procedure 665.5.006, Rev. 24, "Local Leak Rate Tests," also captured this guideline in test acceptance criteria.

The licensee's identification that Oyster Creek was in a condition prohibited by the plant's technical specification required that a licensee event report (LER) be submitted to NRC within 30 days. The licensee's failure to write an LER within the specified time is a violation of the reporting requirements of 10 CFR 50.73, paragraph (a)(2)(i)(B). However, the issue was identified by the licensee, prompt and adequate corrective action was taken, and a late LER was submitted to the NRC within 30 days of identification as required. Also, the inspector could not identify a similar occurrence (failure to write LERs) within two years, corrective action for which should have prevented this occurrence. The safety significance of the event was minimal, as the leakage problem was corrected soon after identification and the plant was in a refueling outage during this time. Therefore, following the regulatory guidance provided in 10 CFR, Part 2, Appendix C, paragraph V.G.1, this violation was not cited.

8.0 INSPECTION HOURS SUMMARY

The inspection consisted of normal, backshift and deep backshift inspection; 30 of the direct inspection hours were performed during backshift periods, and 20 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 February 21, 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:

January 31, 1992	Report No. 50-219/92-02 (EOP Inspection)
February 21, 1992	Report No. 50-219/92-05 (Security Inspection)

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 Section 6.0 of this report.