U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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| Report No. | 91-17 |
| Docket No. | 50-219 |
| License No. | DPR-16 |
| Licensee: | GPU Nuclear Corporation<br>1 Upper Pond Road<br>Parsippany, New Jersey 07054 |
| Facility Name: | Oyster Creek Nuclear Generating Station |
| Inspection Period: | May 19, 1991 - June 22, 1991 |
| Inspectors: | M. Banerjee, Resident Inspector<br>E. Collins, Senior Resident Inspector<br>J. Nakoski, Resident Inspector |

Approved By: Albert W. DeAgazio for 7/26/91
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 conducted outage activities in a safe manner. One noncited violation involved the exceeding of overtime limits for one operator; another noncited violation involved the making of late reports. An unresolved item involved the reporting of main steam isolation valve leak rates. Three previously opened items were closed. An executive summary follows.



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## EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 91-17

### Plant Operations

Overall, GPUN conducted and controlled outage activities in a safe manner. In response to the loss of both diesel generators event, daily evaluation of plant vital functions by the Plant Operation Department was conducted. The actions taken to involve operations management more closely with outage activities in preparation for returning the unit to service was a positive initiative.

### Radiological Controls

No notable observations were made.

### Maintenance/Surveillance

The NRC identified that workers had damaged safety related valves when they used a metal hammer to free a section of pipe in the isolation condenser drain line. This was an example of weak supervision. GPUN testing of the emergency diesel generators demonstrated their capability to carry safety related loads during an emergency with a loss of offsite power. While weak supervision remains a concern, overall, maintenance and surveillance activities continue to be performed adequately.

### Engineering and Technical Support

GPUN evaluation and corrective actions associated with corrosion of emergency service water intake piping and containment spray system nozzle clogging ensured system reliability and demonstrated an appropriate safety approach.

### Physical Security

No significant observations were made.

### Safety Assessment and Quality Verification

Evaluation of core spray concerns adequately addressed system operability; however, permanent resolutions to minimum flow line capacity and minimum flow valve reliability have not been formulated. The root cause standard was still in the early stages of implementation and was considered a positive initiative. Observation team implementation was limited to the area of radiological controls and was not systematic. No other specific initiatives, including plan for excellence initiatives, were identified addressing the weak supervision identified by the diagnostic team evaluation. The late submittals of two reports required by plant technical specifications and 10 CFR 50.72 appeared to be isolated occurrences, with adequate corrective actions taken to prevent reoccurrence.

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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.

# DETAILS

## 1.0 OPERATIONS (71707,93702)

### 1.1 Operations Summary

The plant remained shutdown for the entire inspection period.

### 1.2 Control Room Tours

The inspectors conducted routine tours of the control room. The inspectors reviewed:

- Control Room Operator's and Shift Supervisor's Turnover Check Lists;
- Control Room Operator's and Group Shift Supervisor's Logs;
- Equipment Control Logs;
- Operational Memos and Directives;
- Reactor Building and Turbine Building Tour Sheets;
- Standing Orders; and,
- Technical Specification Log.

No significant observations were made.

### 1.3 Facility Tours

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

- Cable Spreading Room
- Diesel Generator Building
- New Radwaste Building
- Reactor Building
- Vital Switchgear Rooms
- Condenser Bay
- Drywell
- Old Radwaste Building
- Turbine Building
- Intake area

The following additional items were observed or verified on a sample basis:

a. Fire Protection:

- Randomly selected fire extinguishers were accessible and inspected on schedule.
- Fire doors were unobstructed and in their proper position.
- Ignition sources and combustible materials were controlled by the licensee's approved procedures.
- Appropriate fire watches or fire patrols were stationed when fire protection/detection equipment was out of service.

b. Equipment Control:

- Temporary variations and switching and tagging summaries accurately reflected plant conditions.

c. Vital Instrumentation:

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

d. Housekeeping:

- Plant housekeeping and cleanliness were as directed by licensee programs.

At the end of the inspection period NRC inspectors observed that appropriate management attention was applied to plant housekeeping to support plant startup.

**1.4 Control Room Operator Exceeding Overtime Limit**

On June 5, 1991, the licensee initiated a deviation report to address a control room operator exceeding an overtime limit. On Saturday, June 1, 1991, this operator was called in to perform overtime work for the 8:00 a.m. to 4:00 p.m. shift. The group shift supervisor (GSS) incorrectly assessed the operator's eligibility for overtime.

The plant technical specifications require that working hours of staff who perform safety-related functions not exceed 72 hours worked in a 7-day period. The technical specifications also require that any deviation from this guideline be authorized by licensee management.

The licensee indicated that the overtime log was maintained by operations support personnel, who due to a recent staffing change, were no longer available during weekends. The GSS, before deciding to call the operator for overtime duty, did not consult the previous week's overtime log to determine eligibility. Since the day in consideration was a Saturday, some of the previous seven days' work was documented in the previous week's overtime log. Not considering the previous week's work caused the GSS to incorrectly conclude that the operator was eligible for overtime.

The licensee concluded that the root cause was personnel error. The supervisor was counselled on overtime requirements and eligibility. To help supervisors keep track of overtime hours, a running total of the number of shifts worked was added to the weekly overtime log. In addition, operations management planned to distribute a memo to clarify under what conditions a supervisor can change overtime eligibility for shift personnel.

The licensee indicated that control room operators worked an average of 56 hours weekly during the current refueling outage. Given the large scope of outage work and that the licensee generally maintained a five operator shift crew, this number was not considered excessive. The licensee concluded this event was isolated.

This is a violation of plant technical specification requirements; however, safe plant operation was not affected and this violation of an administrative requirement is not considered reportable per the guidance in NUREG 1022, Supplement 1. The inspector concluded the incident was licensee identified, of low safety significance, the licensee's corrective actions appear adequate and, given the isolated nature of this incident, the criteria of V.G.1. of 10 CFR 2, Appendix C for a noncited violation are satisfied. This violation is not being cited.

## 1.5 Oyster Creek Vital Functions While Shut Down

NRC inspectors reviewed GPUN's initiative to evaluate plant vital functions on a daily basis. Operation management identified critical functions, including core cooling, inventory, and electrical power, how those functions were provided, and contingency plans in the event that those functions were lost. This initiative was taken in response to the loss of emergency diesel generator on March 9, 1991, leaving the site with no emergency power. NRC inspectors concluded that this was a positive initiative, and provided management review of safety functions during outage conditions.

## 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 on a sample basis to verify that they were current. 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 work area.

## 3.0 MAINTENANCE/SURVEILLANCE (62703,61726)

## 3.1 Isolation Condenser Drain Line Reinstallation

On May 23, 1991, the NRC inspector questioned the use of a metal hammer to break a weld for isolation condenser drain valves V-14-23 and V-14-24. Upon drain line assembly, GPUN determined that the valve bodies needed to be rotated because of interference with a ventilation duct. The isolation condenser pipe replacement was contracted to General Electric (GE) with Catalytic providing support to GE.

The assembly was being worked on in a pipe clamp on the 75 foot elevation of the reactor building. Three workers were grinding out the socket weld of an elbow to free the section of pipe that contained the two valves. The NRC inspector saw the workers use a metal hammer trying to break the weld after grinding. The NRC inspector questioned the weld supervisor on the activities of the workers and the use of a metal hammer to free the section of pipe. The weld supervisor said a metal hammer was not acceptable. By the time the supervisor went to stop the workers, the section of pipe had already been removed from the elbow.

The valve bodies and pipe section were inspected by the weld supervisor and a quality control (QC) inspector. The valve bodies and pipe section were also examined by the NRC inspector. There was visual evidence of damage to the valve bodies and pipe section. The QC inspector placed a hold tag on the damaged pipe section and valves.

Work on the drain valves was stopped, the involved workers were removed from the job site, and a nonconformance report (NCR) was prepared documenting the damage. A critique was conducted to review the event.

The critique was conducted appropriately. During the critique the workers did not provide a reason why they were using a metal hammer to break the weld. All three recognized, at the critique, that using a metal hammer was not appropriate without using something to buffer the valve bodies to prevent damage. The workers did not realize at the time of the event that they were damaging the valve bodies when using the metal hammer. The facts presented at the critique were representative of the events as they occurred.

GPUN has replaced the damaged valves and pipe. The work the three workers had previously done was reviewed and found acceptable. The involved workers were counselled and then allowed to return to the job site.

The NRC inspector observed the critique and reviewed the licensee's corrective actions. GPUN performed appropriate evaluation of valve damage and implemented adequate corrective actions. The workers recognized that the method they used was not acceptable. The review of the involved workers past work activities did not identify any other concerns. The NRC inspector concluded this event is an example of weak supervision.

### 3.2 Reactor Water Cleanup Valve Nest Access Cover Installation

On June 10, 1991, the NRC inspector observed installation of the access cover over the hole cut in the 75 foot elevation of the reactor building. The hole was cut to allow access to the reactor water cleanup (RWCU) system valve nest for maintenance during the 13R outage. The NRC inspector reviewed job order number 30595. The NRC inspector noted quality assurance and radiological control involvement during performance of the work. The proper approvals were obtained before starting the work. All data required by the job package were recorded. No discrepancies were identified.

### 3.3 Concrete Beam Structural Repair

On June 13, 1991, the NRC inspector observed the preparations to repair an area of spalled concrete in a beam located on the 75 foot elevation of the reactor building. The work was being done using job order number 31814. The defect was documented in material nonconformance report (MNCR) number 910185.

The area requiring repair was between 12 and 18 inches wide by about 4 1/2 inches deep and ran the full width of the beam, about 3 feet. The defect was midspan between two concrete support columns. As part of the repair, the first layer of rebar was exposed to provide a strong interface between the repaired area and the remainder of the beam. The exposed rebar was in good condition. The cause of the spalling was debris left in the concrete when the construction joint was made. To repair the area GPUN used a quick setting concrete patch, Master Flow 928 grout, which has a higher strength than the surrounding concrete. The inspector reviewed the job order and MNCR. No discrepancies were noted.

### 3.4 Reactor Pressure Vessel Hydrostatic Test

GPUN conducted a reactor pressure vessel (RPV) hydrostatic test starting June 2, 1991. The test was done using procedure 602.4.007, revision 14, "ASME RPV Hydrostatic Test." The NRC inspector observed the final test preparations, portions of the reactor coolant heatup, and the final filling and venting of the test boundary.

Procedure prerequisites, precautions, and test equipment temporary variations were reviewed by the inspector. The required approvals were obtained before starting the test . To be sure the procedure was adequately controlled, a senior licensed operator was assigned responsibility to direct the hydrostatic test. The inspector noted quality assurance and operations management involvement during the test.

The main body of the procedure (section 6) stated that reactor coolant heatup and safety valve gagging should be done after filling and venting the test boundary; however, the plant heat up and safety valve gagging were done before completion of filling and venting and were actually performed prior to the start of the test. The NRC inspector determined, based on review of the procedure and discussions with the group shift supervisor (GSS) and plant engineering personnel, that the intent of the procedure was met. However, the procedure was weak in not clearly defining the acceptable sequences for plant heatup, gagging the safety valves, and completing filling and venting of the test boundary. The NRC inspector had no further questions.

### 3.5 Loss of Power Test

The inspector observed performance of Procedure 636.2.001, Rev. 22, "Diesel Generator Automatic Actuation Test," from the control room. The two emergency diesel generators at Oyster Creek are rated at 2500 kw each. During this test, electrical power was removed from station 4160V buses (one train at a time) and a LOCA signal initiated. The plant response was monitored, including the automatic start of the associated emergency diesel and loading of the safety related equipment. This test was done at night to permit verification of plant lighting.

The inspector verified that a controlled copy of the procedure was being used and that involved test personnel were properly briefed by the responsible senior reactor operator (SRO). The inspector verified by sampling that test prerequisites were met. During the test, although some discrepancies were noted, the overall system and equipment response was acceptable. The diesel generators maintained stable voltage, load and frequency, and peak load values were within the acceptance criteria.

During the recovery phase, the inspector noted that the core spray pumps were secured out of sequence before the core spray test return valve was closed and also before the diesel generator was secured. The No. 1 diesel generator parameters were not recorded at a maximum steady state load as required by the procedure. This resulted in some inaccuracy in the documentation of No. 1 diesel parameters. The inspector discussed this discrepancy with the responsible SRO and operations management. Operations has written a memo to their personnel reinforcing the importance of following procedure steps in sequence. The inspector concluded that this deviation from the procedure sequence did not affect the overall acceptability of the test results and the licensee's corrective action was adequate.

Subsequent review of the test results by the licensee indicated that diesel loading sequence timing was not met in four cases, and that about 10 molded case circuit breakers (nonessential loads) did not trip on undervoltage (UV). Also, the containment spray pump motor B breaker was erroneously placed in an open position such that its undervoltage trip function could not be verified. The sequence timer drift did not cause simultaneous loading of multiple loads. The licensee indicated that the sequence timers were adjusted within the acceptable range and the discrepant breakers were either separately tested or left in a tripped condition. The containment spray pump motor B breaker was also separately tested to ensure it performed as required.

Inspection Report 50-219/89-07 documented NRC observations of the loss of power test performed during the 12R refueling outage. This report indicated that the licensee intended to revise the test procedure to include tripping of the molded case circuit breakers (nonessential loads) in the acceptance criteria. Further, the root causes of a large number of the molded case circuit breakers not tripping was evaluated. The licensee determined that molded case circuit breaker performance and UV function would be improved by performing preventive maintenance every 12 months vice every three years.

Diesel operating procedure No. 341, revision 30, included guidance on diesel loading sequence, load rating, and actions to be taken in case load approaches the short term ratings for both loss of power and loss of power with LOCA conditions. Based on discussions with the licensee and a review of the procedures, the inspector concluded that although tripping of the molded case circuit breakers was not specifically addressed in the procedure as an acceptance criterion, the procedure provided adequate guidance to a knowledgeable individual as to the required status and post trip position of the breakers. With the core spray pump initiation logic modified during the current outage, the concern for diesel overloading due to nonessential breakers not tripping was minimized. This modification will prevent a second booster pump on the same diesel to come on line if one booster pump was already running, thus allowing for additional loads to be added to the diesel without overloading the engines.

The inspector concluded that the diesels met the test acceptance criteria, that the procedure was adequate and that test discrepancies were adequately addressed by the licensee.

### 3.6 Core Spray System I Pump Operability Test

On June 22, 1991, NRC inspectors observed surveillance test 610.4.002, revision 23, "Core Spray Pump Operability Testing" for Core Spray System I. Inspectors verified that the current revision of the procedure was used, that shift supervision approval was obtained prior to starting the test, and that test acceptance criteria were satisfied. Inspectors observed startup of the core spray main pump and shift of the core spray booster pumps, including operation of the system on minimum flow. No unacceptable conditions were identified.

## 4.0 ENGINEERING AND TECHNICAL SUPPORT (71707,40500)

### 4.1 Manual Head Vent Valve Installation

As part of the reactor pressure vessel hydrostatic test, the outboard reactor head vent valve, V-25-22, was closed as the test boundary. The inboard head vent valve, V-25-21, was opened. During the hydrostatic test GPUN identified that V-25-22 was leaking about 11 gpm past its seat with a differential pressure of about 800 psi. To isolate the leakage from the reactor vessel to the drywell equipment drain tank (DWEDT) during the hydrostatic test, V-25-21 was closed.

Based on the Updated Final Safety Analysis Report (UFSAR), the head vent valves perform no specific safety function other than maintaining the reactor pressure boundary. During power operations, the head vent valves remain closed with the power removed from the control circuits. When the reactor has been put in cold shutdown, the head vents provide a vessel vent path to the drywell. The valves were designed and installed so that reactor pressure would help keep the valves closed. Both V-25-21 and V-25-22 are solenoid operated valves manufactured by VALCOR, model number AC V526-6770-2. With both V-25-21 and V-25-22 closed there was essentially no leakage past the valves to the DWEDT.

To be sure unnecessary leakage past the head vent valves does not collect in the DWEDT, GPUN has installed a manual valve downstream of V-25-22. This was done to eliminate head vent valve leakage as an identified leakage source. The valve has been located near the DWEDT on the 13 foot elevation of the drywell. Modification OC-MM-402953-009 was used to control installation of manual valve V-22-767. Safety evaluation 402953-010 was prepared to support installation of the manual valve downstream of V-25-22.

During the NRC inspector's review of the safety evaluation, the inspector questioned the assumption that V-25-22 would be able to serve as part of the reactor coolant pressure boundary based on its performance during the reactor coolant system hydrostatic test. The NRC inspector discussed the question with plant engineering and technical functions personnel. The assumption that V-25-22 was acceptable as the reactor coolant pressure boundary (RCPB) was based on information contained in ANSI/ANS 52.1-1983, "Nuclear Safety Criteria for the Design of Stationary Boiling Water Reactor Plants." The safety evaluation adequately addressed the necessary technical concerns. The modification clearly identified the changes to be made.

The NRC inspector reviewed ANSI/ANS 52.1-1983. Using ANSI/ANS 52.1, V-25-22 was classified as safety class 1 (SC-1) and the downstream piping was classified as non-nuclear safety (NNS). Acceptable interface controls between SC-1 and NNS, according to ANSI/ANS 52.1, include two passive flow restricting devices, two administratively closed valves or a combination of both. GPUN concluded the leakage past V-25-22 was such, even with V-25-21 open, that the valve would effectively function as a passive flow restricting device. With V-25-21 administratively closed and V-25-22 acting as a flow restricting device the guidance in ANSI/ANS 52.1-1983 was satisfied. The inspector had no other questions.

### 4.2 Emergency Service Water Piping

The licensee performed emergency service water (ESW) system piping inspection and hydrostatic test at 275 psi during the outage. This inspection and test revealed degraded piping conditions. The ESW system provides cooling water to the containment spray heat exchangers and supports the design function of containment spray system to maintain containment integrity. During normal operation, the pressures at the pump discharge and the heat exchangers are approximately 150 and 100 psi respectively.

The ESW system consists of two system loops. Each loop has two pumps that take suction from the intake. System loop No. 1 pumps are located above the north bay of the intake and system loop No. 2 pumps are located above the south bay. Discharge pipes from the pumps are routed underneath the intake deck and are at least partially submerged in water. The piping is routed underground from the intake to the turbine building. Thereafter system No. 1 and No. 2 pipes are routed differently through the turbine building, to reach the heat exchangers in the reactor building. The ESW piping is internally coated with coal tar. The piping at the intake and underground is also externally coated with coal tar. In addition, underground lines are wrapped with asbestos material and have a water resistant finish.

During 1985, the licensee found that intake structure piping had internal coating degradation. Pieces of coal tar coating were found in the heat exchangers which blocked the heat exchanger tubes. The licensee determined that intake area piping was subjected to thermal cycling and/or mechanical damage during maintenance which resulted in coating degradation. As corrective action, the licensee removed the internal coating from the intake piping. The licensee initiated an inspection program to monitor the condition of the pipe and the remaining coating during plant outages.

The ultrasonic (UT) and visual inspection data base collected during the 11R (1986) and 12R (1989) refueling outages identified external coating degradation in the . ake which was repaired. External pitting was also identified in this portion of the piping. N . other pipe repairs were made. A camera inspection of about 14 to 25 ft of the piping internals, accessible from the intake, showed the piping was in good condition.

The piping inspection (UT and visual) and hydrostatic testing done during the current 13R outage revealed further degraded external coating condition and corrosion including holes and reduced wall thickness in the intake piping. The licensee performed pipe replacement, threadolet repairs and weld overlay repairs of the thinned areas. The external coating was also refurbished. A portion of the removed piping was sent to a laboratory for analysis.

During the outage the licensee also identified blistering of the internal coating of the piping in the turbine building. The heat exchanger outboard valves on the ESW return lines had internal corrosion and were severely degraded. These valves were replaced. In addition, during hydrostatic testing, various flange leaks, including leaks from the system No. 2 heat exchanger flange gaskets were detected. These leaks were repaired.

The licensee attributed the intake area pipe degradation to corrosion due to sea water environment. UT inspection performed on piping in the turbine building showed acceptable wall thickness. Based on these inspection results, the licensee determined that the blistering of internal coating did not affect structural integrity and that minimum wall thickness would be maintained until the next outage. The licensee was formulating an inspection plan for the next refueling outage.

The inspector concluded that the licensee made the required repairs. Based on the results of the licensee's inspection and a successful hydrostatic test at 275 psig, the system integrity is maintained. The inspector did not have any other concerns.

### 4.3 Containment Spray Nozzles

During the containment spray header air test, six of the ten torus spray header nozzles were found completely blocked and corroded. The remaining four nozzles were partially blocked. Only one out of 176 nozzles in the drywell spray headers was found blocked. This test was done as part of the 10-year ASME Section XI inservice test program.

The licensee evaluated the conditions and determined the necessary corrective actions. A safety evaluation was performed to determine and document the safety significance of the blocked torus spray nozzles. The torus spray nozzles provide cooling to the torus air space, and blocked torus nozzles do not affect torus pool cooling. The evaluation concluded that loss of spray flow to the torus air space did not degrade design basis accident mitigation. Due to the minimal safety significance, GPUN concluded the condition was not reportable.

The licensee indicated that the torus spray header contains bronze nozzles on carbon steel nipples. The torus nozzles were found somewhat damp and galvanic corrosion was suspected to be the cause of nozzle blockage. The torus spray header was flushed. No significant debris was found. The torus nozzles were replaced and a review to further evaluate galvanic corrosion was initiated. The licensee found some paper material blocking one drywell spray header nozzle. The other nozzles were found clean and dry. No corrosion was evident in the drywell spray nozzles. The blocked drywell nozzle had no impact on system operability. The licensee plans to inspect the nozzles during the next refueling outage.

The inspector concluded that the licensee's response and short term corrective actions were appropriate and that the safety significance of blocked torus spray nozzles was low. The inspector had no other questions.

## 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 to verify that they were properly locked or guarded and that access control was in accordance with the Security Plan. No significant observations were made.

## 6.0 SAFETY ASSESSMENT/QUALITY ASSURANCE (40500,71707)

### 6.1 Licensee Event Report Not Submitted

On June 6, 1991, the licensee initiated a deviation report documenting that certain local leak rate test (LLRT) failures did not result in Licensee Event Reports (LER). Failure of an LLRT to meet the plant technical specification acceptance criteria requires an LER. The acceptance criteria require that the combined leakage rate of all penetrations and isolation valves (type B and C tests) shall be less than 0.60 of the maximum allowable leak rate limit (La) at 35 psig. The leakage rate of a main steam isolation valve (MSIV) is limited to 5% of the allowable operational leakage rate (Ltm) at 20 psig by the acceptance criteria.

Testing of the MSIVs identified that one valve exceeded the 5% criterion. Additional testing identified that one of the two reactor building-to-torus vacuum breaker lines exceeded the combined leakage rate criterion. Deviation reports were written documenting these test failures; however, while reviewing the second event for an LER, the licensee realized that an LER was missed on the first event. GPUN evaluated the failure to write an LER and concluded that failure to understand the technical specification requirements related to LLRT resulted in the missed LER. Plant technical specification, Section 4.5.F, "Acceptance Criteria," was revised in amendment 132 at the end of the last refueling outage (12R). Section 4.5.F was previously entitled "Corrective Action" and not "Acceptance Criteria" and was not considered by the licensee as a failure to meet plant technical specification requirements. The LLRT engineer wrote a memorandum to various plant personnel involved in making the reportability determination. This memo explained the LLRT acceptance criteria and when an LLRT failure was reportable. The licensee is currently determining if additional corrective actions are necessary to help field personnel understand when deviation reports are to be initiated on LLRT failures so that potential reportability of the event may be considered. This item will remain unresolved pending completion of the licensee's determination. (50-219/91-17-01)

## 6.2 Review of Report Timeliness

Recently there were two examples when required reports were not made in the time frame required by plant technical specifications or by 10 CFR 50.72. On March 14, 1991, GPUN issued Special Report No. 91-02. This report was issued after the 30 day period allowed by technical specification (TS) 3.12.E. The second late report involved the notification of an offsite government agency on a potentially contaminated spill that occurred on May 4, 1991. GPUN's public affairs department informed the local police department of the spill as required by station procedure 126, revision 12, "Procedure for Notification of Station Events." GPUN determined this notification of an offsite government agency required a 4 hour notification of the NRC as required by 10 CFR 50.72(b)(2)(vi). The NRC notification was made on May 6, 1991.

The NRC inspector discussed Special Report No. 91-02 with the responsible site licensing engineer. Based on that discussion, the inspector concluded the cause of the late report was a lack of communications between the station fire protection engineer and site licensing. The station fire protection engineer had sent site licensing a draft special report. This report was not received by site licensing. The report was required to be issued by December 24, 1991. On January 2, 1991, the group shift supervisor (GSS) wrote a deviation report (DVR) documenting that a special report had not been issued on a non-functional fire barrier door that was required by TS 3.12.E to be repaired within seven days. The fire protection engineer closed out the DVR and stated that a special report had been issued. At about this time, the fire protection engineer left GPUN. The new fire protection engineer was not aware the report had not been issued. When the DVR was routed to the responsible site licensing engineer he realized the special report had not been issued. The licensing engineer started action to issue the report.

Station procedure 126 has requirements for the public affairs department to notify local officials of events classified as public interest. When water from the condensate storage tank leaked onto the ground during maintenance, the public affairs department informed the local police department as required by procedure 126. At the time, no NRC report was seen as required by public affairs, and therefore the control room was not informed of the notification. A DVR was issued to document this condition on May 6, 1991. The resolution to the DVR was to make the 4 hour NRC notification. To correct this condition in the interim, procedure 126 was temporarily changed to require an NRC 4 hour notification when public affairs notifies an offsite government agency. The inspector reviewed station procedure 126 and discussed the occurrence with public affairs and operations personnel. Subsequent 4 hour NRC notifications have been properly made.

Based on the NRC inspector's procedure reviews and discussions, GPUN's actions to resolve both the late special report and the late 4 hour notification, were adequate and timely. They could not have been prevented as a result of corrective action to a previous violation. These items however constitute violations of TS 3.12.E and 10 CFR 50.72 respectively. No notice of violation will be issued based on GPUN's corrective actions and in accordance with 10 CFR 2 Appendix C, paragraph V.G.1.

### 6.3 Root Cause Analysis

NRC inspectors reviewed Oyster Creek's root cause standard and selected deviation reports to assess the effectiveness of the root cause analysis. Oyster Creek procedural implementation of the root cause standard is in development.

At Oyster Creek, the deviation report procedure serves as the controlling procedure for the initiation, assignment, and close out of root cause evaluation. Station Procedure 140, "Conduct of Root Cause Evaluations," is still under development. The root cause standard specifies that a root cause assignment group, consisting of senior department representatives, evaluate all deviation reports and designate the degree of root cause evaluation required. The root cause standard provides guidelines for the assignment of the root cause category based on the degree of risk associated with not finding the root cause and the degree of uncertainty as to what the root cause is. The four categories are defined.

Category A: This is the most rigorous process. A team is assigned to pursue the root cause using analytical techniques such as Kepner-Tregoe, modified Kepner-Tregoe, human performance enhancement system and barrier analysis. This category is characterized by high risk and high uncertainty in finding a root cause.

Category B: This is the next most rigorous process. A team leader is assigned to pursue the root cause using the above listed analytical techniques. This category is characterized by moderate risk and high uncertainty in finding a root cause or high risk and moderate uncertainty in finding a root cause.

Category C: A knowledgeable individual is assigned to perform the root cause analysis. Analytical techniques may be used but are not required. This category is characterized by moderate risk and moderate or low uncertainty as to the root cause.

Category D: This is the least rigorous and generally will not involve more than one person nor will it involve a review of data significantly greater than that provided in the deviation report. It is characterized by low risk, regardless of the level of uncertainty in determining the root cause.

NRC inspectors reviewed deviation reports 91-314 and 91-405 which were classified as category D root cause determinations. Also, NRC inspectors reviewed deviation reports 91-212 and 91-074 which were classified as category C root cause determination. NRC inspectors concluded the causes identified, the level of analysis applied and the actions to address the causes were consistent with the root cause standards.

Deviation report 91-307 was reviewed by the NRC inspectors. This deviation was assigned a category A root cause determination. The level of effort applied for this deviation was a disposition to a material nonconformance report. No other level of root cause analysis was applied. The NRC inspector concluded that this effort was not consistent with that required by the root cause standard. This nonimplementation of the root cause standard was discussed with the safety review manager. The deviation report was reviewed again by the root cause assignment group, and was reclassified to a level C. The level of effort performed was consistent with that required by level C root cause determination.

The deviation report documenting the failure of No. 2 emergency diesel generator during surveillance testing on March 9, 1991, was reviewed by the NRC inspectors. Deviation report 91-210 was assigned category A root cause determination. NRC inspectors reviewed the documentation associated with the root cause analysis. For this event, a modified Kepner-Tregoe approach was used. Also, the independent onsite safety review group analyzed the event. While the modified Kepner-Tregoe performed detailed engineering evaluation and analysis of failure mechanisms, it was the independent onsite safety review group that actually identified the apparent root causes for the failure of the diesel generator. The NRC inspector concluded the level of effort applied was consistent with the root cause standard.

NRC inspectors reviewed the root cause analysis associated with deviation reports 91-566, 91-567 and 91-524 associated with core spray system II support damage. These deviation reports were ultimately assigned root cause category A determination. Oyster Creek documented their conclusions and evaluation in a position paper dated June 21, 1991. Oyster Creek used this position paper to document the cause determinations and implementation of the root cause standard. NRC inspectors concluded that significant engineering effort was applied in evaluating the causes for core spray system II support damage. The cause was documented as deficiencies associated with the core spray booster pump bypass check valve. Corrective actions were implemented and subsequently tested to verify that water hammer had been eliminated. While significant effort was expended, the root cause methodology applied in the position paper was not evident or documented. For this event, while the likely causes were identified, the root cause standard was not implemented because the methodologies were not used.

The Oyster Creek root cause standard was still early in its stages of implementation. The standard represents a sound approach to root cause analysis. The standard has resulted in consistent assignment by management of the root cause determination method required. The root cause analyses assigned category C and D efforts were appropriate. The root cause analyses assigned category A and B received significant engineering efforts; however, the root cause standard was not fully implemented in all cases. Overall, the implementation of the root cause standard is considered a positive initiative.

### 6.4 Resolution of Core Spray System Issues

NRC inspectors reviewed GPUN evaluation and corrective actions for three core spray system issues. The first issue was the adequacy of the minimum flow rate to support extended operation of the core spray system on minimum recirculation flow (unresolved item 50-219/91-03-02 and Bulletin 88-04). The second issue involved the design and operation of core spray minimum flow valves during the design basis accident with the loss of offsite power (preliminary safety concern (PSC) 90-005). The third issue addressed GPUN's resolution of repeated core spray system II pipe support damage apparently caused by water hammer. Conference calls were conducted involving NRC resident inspectors, NRC Region I office, NRC Headquarters Nuclear Reactor Regulation Office and GPU Nuclear on June 11 and June 18, 1991. An additional conference call was conducted between NRC Region I office and GPU Nuclear on June 19, 1991.

GPUN, in consultation with the manufacturer of the core spray system pumps, concluded that operation of core spray system on minimum flow during an accident should not exceed four hours and that four hours of continuous operation on minimum flow was acceptable as long as vibrations do not exceed 0.55 inch per second. GPUN concluded that vibration measurement was the aggregate indicator for reliable pump performance at low flow and that this measurement captured concerns associated with hydraulic instability. Long term mechanical deterioration of the pump bearings and mechanical seals was expected but pump failure was not. GPUN historical vibration information, with the core spray pump on minimum flow, indicates a maximum vibration for any pump of 0.54 inch per second. GPUN concluded, from historical data, there has been no deterioration in the performance of the core spray system pumps. This data included about 10 hours of intermittent operation on minimum flow. GPUN concluded from this historical performance there is reason to believe that an additional 10 hours of intermittent operation can be tolerated without adversely affecting system reliability. GPUN evaluation of pump performance at accident conditions concluded that net positive suction head (NPSH) requirements are satisfied with margin and that the expected vibration levels during an accident should not be significantly higher than those measured using cold water.

GPUN implemented procedure changes to Station Procedure 308, revision 42, "Emergency Core Cooling System Operation." The objective of these procedure changes was to limit minimum flow operation during accident conditions. Temporary change 6/21/91-9 was implemented on June 21, 1991, directing operators to establish system flow using the test return valve if cycling of the core spray parallel valves is required for more than two hours. NRC inspectors reviewed temporary change 6/21/91-9 on June 22, 1991, and verified that sufficient guidance was given to the operator to minimize core spray pump operation on minimum flow.

The second issue, preliminary safety concern (PSC) 90-005 raised a concern with respect to potential failure of the core spray system due to repeated momentum induced water hammer. This concern was postulated due to core spray minimum flow valves, which are air-operated, failing in the open position on a loss of offsite power, introducing the possibility of core spray system piping drain down, and subsequent momentum induced water hammers by starting and stopping the core spray system pumps in order to control reactor water level. GPUN evaluated the effects of potential system drain down under this configuration and concluded that it would not impact the safety function and operability of the core spray system.

During refueling outage 13R, GPUN added an alarm function to core spray systems I and II to alert the operator upon loss of the keep-fill system or drain down of core spray system piping. GPUN also implemented operational procedural changes to caution the operator that under these conditions, the minimum flow valves will fail to the open position, that cycling of the core spray system pumps with the fill system not in operation may cause system water hammer, and that extended operation of the core spray system on minimum recirculation flow may cause pump damage. Specific guidance was provided to the operators to remove any core spray pump from service not required to ensure adequate core cooling. The procedures were changed to direct the operator to confirm the keep-fill system running, and if unable to make this confirmation, the operator is directed to maintain the system full using the condensate transfer system. If unable to keep the system full of water using this method the operator is directed to start the core spay main pump to keep the system full. These procedure changes were implemented to Station Procedure 308, revision 42, "Emergency Core Cooling System Operation," using temporary change No. 6/21/91-5 implemented on June 21, 1991. NRC inspectors reviewed this temporary change on June 22, 1991, and verified that these additional precautions and instructions to the operator to keep the system full were implemented.

In regard to the third issue, GPUN concluded that the cause of core spray system II pipe support damage was a malfunctioning core spray booster pump bypass check valve causing momentum induced water hammer (although air entrapment water hammer could not be eliminated). On establishing flow from core spray main pumps through the booster pump bypass check valve, GPUN concluded that subsequent lowering of flow to minimum flow concurrent with the bypass check valve remaining open and subsequent start of the booster pump caused system water hammer when the bypass check valve slammed closed. GPUN concluded the support damage on system II, while requiring repair and actions to prevent recurrence, did not affect core spray system operability. Repairs were performed on the core spray system II bypass check valve consisting of removing a key fixing the check valve to the valve stem and refurbishing the valve disc backstop and packing gland area. Subsequent testing of core spray system II confirmed proper operation of the bypass check valve and the elimination of this effect. NRC observation of core spray system operation on June 12, 1991, confirmed that upon core spray booster pump start with the bypass check valve closed, no significant pressure transient occurred to the system.

GPUN evaluated core spray system I for a similar effect. Based on satisfactory results from inspection of the core spray system I booster pump bypass check valve and the absence of any water hammer effects on system I, GPUN concluded this problem does not exist in core spray system I.

Overall, NRC inspectors concluded that GPUN actions to repair the core spray system II booster pump bypass check valve, operational procedural changes to provide alternate methods for keeping core spray systems filled upon loss of offsite power, and procedural changes providing the operators with alternate methods to minimize core spray pump operation on minimum flow help ensure the operability and reliability of the core spray system during accident conditions. Since long term corrective actions still needed to be implemented to address core spray system minimum flow questions, unresolved item 50-219/91-03-02 remains open. NRC inspectors further concluded that long term corrective actions were needed to enhance core spray system minimum flow valve design to ensure minimum flow valve functionality during accident conditions.

### 6.5 GPUN Initiatives to Address Weak Supervision

An NRC Diagnostic Evaluation Team, conducted in November 1990, concluded that one of the causes for a slow rate of performance improvement at Oyster Creek was weak supervision. NRC inspectors evaluated current GPUN initiatives to address weak supervision, including a summary of teamwork and leadership initiatives planned for 1991 and the status of GPUN initiatives to formulate and implement observation teams to instruct workers and supervisors. NRC inspectors did not find in the summary of teamwork and leadership initiatives any specific items to address weak supervision. In regard to observation teams, while some observation efforts have been implemented in the area of radiological controls, the effort applied was not systematic and no initiatives have been implemented in other functional areas. Discussion with GPUN management confirmed that systematic implementation of the observation teams has not occurred. GPUN management also indicated that their specific initiatives to address weak supervision have not been formulated. To date, resources have been focused on completion of the 13R outage and returning the plant to service. NRC inspector review of the plan for excellence also did not find any current initiatives to address weak supervision.

## 7.0 REVIEW OF PREVIOUSLY OPENED ITEMS (92701,92702)

(Closed) Violation 50-219/90-06-01. This violation documented the failure to station a continuous fire watch in the cable spreading room when the fire detection system was inoperable. GPUN stated the cause of this occurrence was a lack of understanding by Operation Department supervisory personnel on the implication of a trouble alarm on the control room fire panel. Senior Operations Department management issued guidance to the supervisory personnel. The guidance directed the Group Shift Supervisors (GSS) and Group Operating Supervisors (GOS) to declare instrumentation and suppression systems inoperable when a trouble alarm has been received on the control room fire panel.

The NRC inspector reviewed GPUN's response and the summary of the event critique. GPUN's response adequately addressed the subject of the violation. Corrective actions identified in the critique summary adequately address the broader issue of missing fire watch tours in general.

The NRC inspector reviewed the guidance provided to the GSSs and GOSs in a memorandum dated May 18, 1990, from the Manager, Operations Support. The memorandum clearly defined the actions required when a trouble alarm has been received on the control room fire panel. Additionally, guidance was provided to be sure maintenance has been started in a timely manner. The NRC inspector interviewed a GSS to determine his knowledge of management's guidance. The GSS was familiar with the event. He had adequate knowledge of the actions to take if a detection system trouble alarm was received on the control room fire panel. This item is closed.

(Closed) Violation 50-219/90-06-02. This violation involved not having the rod worth minimizer (RWM) operable during a plant startup on February 15, 1990. The plant technical specifications require that the RWM be operable during each reactor startup until reactor power reaches 10% of rated power.

In their response to the notice of violation, the licensee indicated that immediately after identification of the condition, the RWM keylock switch was returned to the "normal" position. The rod withdrawal sequence was reviewed to verify that rods were withdrawn in correct sequence. The licensee performed a critique and made the critique report "required reading" for appropriate operations personnel.

To prevent recurrence, procedure changes were made to require verification of RWM keylock switch position and a functional test of the RWM prior to each reactor startup. The inspector reviewed Procedure 201.1, revision 53, "Approach to Criticality," and verified these corrective actions. This item is closed.

(Closed) Unresolved Item 50-219/90-07-01. Inservice test results indicated that the test return valve for core spray system II had stroke times that could result in exceeding the Appendix K analysis assumption for establishing full core spray flow. This item was left open pending completion of the licensee's analysis to determine the effect of valve stroke time increase from 20 seconds to 23 seconds for the test return valve.

The inspector reviewed the licensee's analysis which concluded the increased valve closure time of 23 seconds does not adversely affect the capability to obtain required core spray flow within the time assumed in the analysis. The inspector also noted that the valve closure time was adjusted to close in 20 seconds as shown by the subsequent IST results (20.5 seconds was used as IST criterion). The inspector concluded the system design flow requirement was met with the current test valve closure time. This item is closed.

## 8.0 INSPECTION HOURS SUMMARY

The inspection consisted of normal, backshift and deep backshift inspection; 62 of the direct inspection hours were performed during backshift periods, and 19 of these were deep backshift hours.

## 9.0 EXIT MEETING AND UNRESOLVED ITEMS (40500,71707)

### 9.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on June 27, 1991. During the inspection, licensee management was periodically notified 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

On May 23, 1991, the resident inspectors attended the exit meeting for inspection 50-219/91-18. At this meeting 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. An unresolved item is discussed in paragraph 6.1 of this report.