U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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| Report No. | 91-37 |
| 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: | November 10, 1991 - December 14, 1991 |
| Inspectors: | M. Banerjee, Resident Inspector<br>T. Frye, Reactor Engineer, DRP<br>R. McBrearty, Reactor Engineer, DRS (section 4.3)<br>J. Nakoski, Resident Inspector<br>D. Vito, Senior Resident Inspector |

Approved By: Paul D. Kaufman for W. H. Ruland, Chief, Reactor Projects Section 4B — 1/16/92 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. A non-cited violation on the failure to have boron enrichment sample results 30 days following a refueling outage is documented in this inspection report. One unresolved item is opened regarding the maintenance and testing of the technical support center (TSC) ventilation system and on the means by which the licensee has met the requirements of NUREG 0737 for TSC habitability. A Notice of Violation is included documenting the licensee's failure to adequately implement the controls necessary to maintain proper usage of measuring and test equipment (M&TE). An unresolved item is also included regarding the ultrasonic testing of weld overlays at Oyster Creek.

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

# EXECUTIVE SUMMARY

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## Plant Operations

Overall, GPUN conducted plant activities in a safe manner. Operator performance was good. Management involvement was evident. The licensee's response to a non-conservative error in the feedwater flow input to the heat balance equation that resulted in operation of the unit above its licensed limit was adequate. The NRC had identified a concern with the technical specification required surveillance of boron-10 enrichment in the standby liquid control system. In response the licensee was seeking a technical specification change to clarify the boron enrichment sampling requirements. Corrective actions by the licensee in resolving the boron-10 sampling requirements were adequate.

## Maintenance/Surveillance

Maintenance and surveillance activities observed during this inspection period were generally well controlled and conducted. After the NRC identified concerns, the licensee began a review of the motor operated valve preventive maintenance program to develop improved methods for application and use of grease. The drywell sand-bed removal project was being well-controlled, without any significant unforeseen problems encountered. Poor implementation of the requirements for the control of measuring and test equipment and the identification of the weakness by the NRC on two separate occasions, resulted in the issuance of a Notice of Violation.

## Engineering and Technical Support

Engineering support to operations and maintenance was adequate. An example of good engineering support to maintenance was noted during testing of the 1-2 diesel fire pump to develop the appropriate work instructions for repairs to be performed. Engineering support in resolving the difficulties identified with torus venting and purging were good and resulted in comprehensive guidance being provided to operators within the emergency operating procedures for venting and purging the torus. NRC review of the technical support center (TSC) ventilation system raised concerns with maintenance and testing of the TSC ventilation system and on how the requirements of NUREG 0737, Supplement 1, were being met for TSC habitability. The TSC ventilation system concerns remain unresolved pending NRC review of the licensee's evaluation of the design criteria, licensing commitments, and maintenance history. The NRC identified a discrepancy in the non-destructive examination methods used at Oyster Creek when examining weld overlays used for repair of intergranular stress corrosion cracking (IGSCC).

The adequacy of the overlay examinations performed at Oyster Creek were questionable. The licensee, in conjunction with EPRI, committed to perform a study of their examination method to determine acceptability. The weld overlay examination concern remains unresolved pending completion of the licensee's study and NRC review of the results.

Emergency Preparedness

See engineering and technical support for concerns with the TSC ventilation system. No other notable observations.

Safety Assessment and Quality Verification

The operator concern program is working well. Reasonable efforts are being made to provide timely response to both current and backlogged issues. The operators appear to have accepted the program and see it as a legitimate means to help improve their work environment. The program has recently been expanded so that other plant departments may provide input.

DETAILS

## 1.0 OPERATIONS (71707,71710,93702)

### 1.1 Operations Summary

The unit operated at or near 100% power during the inspection period. Power level was limited for a significant portion of the inspection period to approximately 99% power due to a leak in a level column on the 1-5 heater drain tank. The second stage reheaters were isolated to minimize the leak, thus limiting total power output. Power was also administratively limited to 98% (1906 MWt) power between November 13, 1991, and November 18, 1991, after GPUN verified an inaccuracy in the computer generated heat balance calculation.

Following calibration of the individual flow nozzles on the three feedwater strings by Combustion Engineering, the flow orifice discharge coefficients which are an input to the plant heat balance calculation were found to be in error. The existing orifice discharge coefficients were found to be approximately 1.19% non-conservative, i.e., actual power was 1.19% higher than indicated power. While the calibration of the orifices resolved a long-standing question regarding an indicated steam flow/feed flow mismatch at Oyster Creek, it validated that the unit had operated at higher than the licensed thermal power limit (1930 MWt) for lengthy periods of time since initial licensing of the plant. GPUN reported this issue to NRC via a December 13, 1991, Licensee Event Report, and concluded that the error was within allowable margins for core thermal power.

While the non-conservative error, by itself, was within assumed design allowances (i.e., less than 2% above the licensed thermal power limit), Oyster Creek has made other corrections of non-conservative errors in the heat balance calculation in the past. The combined effects of these errors will be evaluated in more detail in future inspections.

On November 13, 1991, Emergency Service Water (ESW) pump 52B was declared inoperable after failing its inservice test. After replacing the pump internals, ESW pump 52B was successfully tested and returned to service on November 20, 1991, and the 15-day technical specification limiting condition for operation (LCO) action statement shutdown clock was exited.

On November 29, 1991, GPUN began removal of the sand between the steel drywell liner and the concrete shield wall. Removal of the sand bed is intended to eliminate the cause of accelerated corrosion of the outer drywell wall by removing the galvanic cell created between the outer drywell wall and the rebar of the shield wall, through the moisture of the sand bed. Details are provided in section 3.6.

On December 12, 1991, ESW pump 52A was declared inoperable after failing its inservice test (IST) due to low developed differential pressure (dp). The pump dp was in the IST required action range. A seven-day technical specification LCO action statement was entered. The previous surveillance failure of ESW pump 52B in November 1991 was attributed to normal wear of the pump internals. ESW pump 52A had been in service for approximately six years without any significant overhaul before failing the IST in December 1991. This may be indicative of a weakness in the preventive maintenance program for the ESW pumps that resulted in a common mode failure of ESW pumps 52A and 52B. The ESW pumps (52C and 52D) in the other train of containment spray/ESW system continue to pass their routine IST surveillance. With the replacement/repair and satisfactory performance during IST surveillances of ESW pumps 52A and 52B, the concern with the continued operability of the containment spray/ESW system was minimized. The resident staff continues to monitor the licensee's maintenance program and the development of improved preventive maintenance programs for rotating equipment.

### 1.2 Standby Liquid Control System Walkdown

The inspector conducted a walkdown inspection of the standby liquid control (SLC) system. The Final Safety Analysis Report (FSAR) and technical specifications (TS) were reviewed to determine the surveillance requirements and limiting conditions for operation of the system. The system piping and instrument drawing (P&ID) were compared against the system valve lineup in the SLC operating procedure to ensure that the system valve lineup was accurate and appropriately places the system in standby readiness.

The inspector walked down accessible portions of the SLC system. This was done to verify that the actual system lineup agreed with the operating procedure valve lineup. Also, the walkdown verified that the condition of the components and equipment was satisfactory to assure system operability. The control room copy valve lineup was reviewed to ensure that it was complete and properly documented. SLC system indications and the control room switch lineups were walked down to ensure that the system was in standby readiness. The inspector verified that the poison tank level and the tank temperature met TS 3.2.C.2 requirements and that the analysis of the boron concentration showed acceptable results. The inspector observed the performance of surveillance procedure 612.4.001, "Standby Liquid Control System Functional Test," and the concurrent performance of hydrostatic testing on the pump discharge piping (see section 3.5).

During the review of the P&ID and system valve lineup, two minor valve position discrepancies were noted. The system valve lineup showed the required position of V-19-12 as closed and V-19-49 as locked closed. These positions agreed with the actual valve positions in the plant. However, P&ID 148F723, Rev. 22, showed V-19-12 as locked closed vice closed and V-19-49 as closed vice locked closed. These two discrepancies were brought to the group shift supervisor's attention for resolution. The as-found configuration was determined to be correct and a drawing change was initiated.

The walkdown inspection of the SLC system resulted in no other notable findings. Based on this walkdown and procedure review, the inspector concluded that the system would perform its intended function.

**1.2.1 Verification of SLC System Surveillance**

The inspector reviewed the following procedures to ensure that the surveillances were being completed as required by technical specifications:

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| 612.4.001, Rev. 17 | Standby Liquid Control Pump and Valve Operability and Inservice Test (IST) |
| 612.4.002, Rev. 19 | Standby Liquid Control System Functional Test |
| 828.9, Rev. 5 | Secondary System Analysis: Liquid Poison |

During the review of the SLC poison tank sample analysis results taken per procedure 828.9, the inspector noted that the Boron-10 enrichment sample was last obtained on October 1, 1990, and analyzed on October 4, 1990. TS 4.2.E requires that this sample and analysis be performed every refueling outage. This technical specification also requires that the enrichment analysis be received no later than 30 days after startup from the refueling outage. The inspectors questioned the licensee as to why the last Boron-10 enrichment analysis was performed in October 1990, instead of in June 1991 (at the end of the 13R refueling outage). The licensee stated that based on TS definition 1.12, "Refueling Outage," this surveillance was being performed every 24 months. The inspectors noted that this surveillance frequency did not appear to address the statements made in the TS specifically relating the Boron-10 enrichment sample to startup after a refueling outage. The inspector requested the licensee to describe the basis for the specific wording in the TS and justify why their current surveillance frequency was acceptable.

The licensee responded that it was not necessary to reverify boron-10 enrichment based on a specific event, such as a refueling outage, unless the contents of the liquid poison tank were changed or enriched boron was added to the existing tank volume. The enriched boron was purchased from a qualified vendor and each shipment was accompanied by a certificate of conformance. Verification of the Boron-10 enrichment through sampling is simply a validation of the receipt of qualified material. The initial shipment of boron-10 enriched sodium pentaborate decahydrate was received at Oyster Creek in December 1987. GPUN had an independent laboratory analysis done that month to verify the boron-10 enrichment before use of the material.

The licensee noted that the TS surveillance requirement was derived from the minutes of an April 3, 1987, BWR Owners' Group (BWROG) meeting on compliance with the anticipated transient without scram (ATWS) rule (10 CFR 50.62). These meeting minutes recommended Boron-10 enrichment measurement "at the beginning of each cycle to assure proper shutdown capability." This wording was included in the licensee's TS change request of May 10, 1988, to support the use of enriched Boron-10. The licensee amendment request was approved by NRC on July 14, 1988.

Enriched boron was added to the liquid poison tank for the first time in October 1988, during the 12R refueling outage. A sample was taken shortly thereafter and the analysis report was received on November 3, 1988, verifying the Boron-10 enrichment. In January 1989, the Boron-10 enrichment sampling requirement was placed on the master surveillance list as a "refueling interval" surveillance test, and a specified time interval was applied (20 months at that time; now 24 months). Since that time, the wording of TS 4.2.E has not been specifically addressed.

The inspector reviewed the licensee's safety evaluation which addressed the use of enriched sodium pentaborate solution in the SLC system (SE No. 328232-001, dated January 7, 1988); the TS amendment request dated May 10, 1988; the approved TS amendment dated July 14, 1988, with accompanying NRC safety evaluation; the BWROG meeting minutes dated April 3, 1987; the vendor (Centronic, Ltd.) certificate of conformance for the enriched sodium pentaborate dated December 4, 1987; and the Boron-10 enrichment analysis results since that time. The inspector also contacted NRR technical review personnel for their current position on Boron-10 enrichment analysis requirements.

The inspector concluded that the verification of Boron-10 enrichment is most appropriately addressed through the procurement process (i.e., through the receipt of qualified material). Sampling, either periodically and/or after adding boron to the tank, would provide an additional verification of Boron-10 enrichment. The licensee has committed to preparing a proposed TS change to reflect a more appropriate surveillance requirement. The licensee has also committed to implement, on an interim basis, the guidance of the proposed TS change while the change was being processed. This violation of TS 4.2.E was not cited as allowed by 10 CFR Part 2, Appendix C, Section V.A, because of the minor technical significance of the issue in question, the isolated nature of the violation, and because appropriate corrective actions were committed to prior to the end of the inspection.

### 1.3 Control Room Tagging

On November 14, 1991, the licensee implemented a new system for the logging and display of control room panel deficiency and information tags. Basically, the change involved the replacement of the control panel tags with uniquely identified magnetic circular markers. The licensee stated that the reason for the change was to reduce control board clutter by removing the tags, since most of the tags did not contain information which was necessary for the operators to respond to plant events. The licensee also stated that this change was being implemented on a trial basis so that the effects of the change and the degree of operator acceptance could be assessed before it was implemented permanently. In addition to reviewing the documentation which implemented the change and observing control room operator use of the new system, the inspectors interviewed several control room operators to determine their initial assessment of system effectiveness.

In the past, colored tags (pink for control panel deficiencies and orange for control panel information tags) were used to document pertinent information. A brief description of the item in question was written on each tag, and the tag was placed on the control panel adjacent to the affected instrument. Under the new system, the magnetic markers have been placed on the control panels in place of the tags. The markers are colored similarly to the tags and each marker is uniquely numbered. A log book is kept which retains the descriptive tag for each item and relates the tag to the marker on the control board via the numbering system. The descriptive tags were still being filled out and retained because of the trial status of the program.

The inspectors reviewed the temporary procedure change (TPC) to Procedure 108, "Equipment Control," Rev. 50, dated November 13, 1991, which implemented the new program. The TPC provided adequate description of the program and guidance for the operators. The TPC retains the option for the control room operators to place an information tag on the control panel instead of a marker. This option would be used when the operators feel that they need quicker access to the information provided on the tag to respond to a plant event (i.e., quicker than having to look in the log book for related information). Control room deficiencies are exclusively designated by markers.

The inspectors discussed the implementation of the new system with several control room operating crews, along with their respective group shift supervisors (GSS). The operators agreed almost unanimously that control board deficiencies could be appropriately treated through the use of the markers. Since the problems associated with the control board deficiencies were intuitively obvious (meter downscale, recorder broken, . . . ), the markers provided adequate reminders to the operator. Some reservations were expressed by the operators, however, regarding the use of the markers in place of the information tags. The majority of the operator comments dealt with the need to assure that information tags remain on the control panels for those items for which response time was critical. Conversely, most of the operators noted that it was not that difficult to maintain a general familiarity with the reasons for the information tag markers and that their detailed shift turnovers provided a continuous reminder of the location of and reason for each marker. The operators were cognizant of their option to place an information tag on the control panel instead of a marker if deemed necessary.

The inspectors reviewed the log book which provided the descriptions of the deficiency and information markers currently on the control room panels. The inspectors concluded that the log book provided for appropriate recording and control of the markers. With regard to the information tag markers, the inspectors questioned whether several specific items designated by markers should be more appropriately addressed by placement of the information tag on the control board. The licensee reviewed those markers in question and agreed that one of them would be more appropriately addressed by a tag on the control board. The licensee provided adequate justification to the inspectors as to why the other information tag markers questioned did not warrant placement of a tag. The inspectors will continue to monitor the use of the new control room panel marking system.

### 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 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.

### 1.4.1 Control Room Tour - Verification of APRM Operability

On December 9, 1991, the following local power range monitors (LPRMs) detectors which input to average power range monitor (APRM) channels were inoperable:

04-33B, 12-17A, 20-25B, 20-49D, 28-49B, 28-25C and 44-25C

The inspectors assessed APRM operability based on the number of failed or inoperable LPRM detectors to ensure technical specification requirements were met.

The plant technical specification requires that an APRM channel be made inoperable if four of the LPRM chambers assigned to the APRM become inoperable, or if two LPRM chambers in the same radial core location assigned to the APRM become inoperable. The plant technical specifications also require that any two LPRM assemblies which are input to the APRM system and are separated in distance by less than three times the control rod pitch may not contain a combination of more than three inoperable detectors out of four detectors located in either A and B or the C and D levels.

The licensee controls and monitors the allowable bypass configuration for the APRM/LPRM system by using Standing Order No. 21. This standing order requires that an LPRM/APRM status information sheet be revised and approved by the core engineering manager and maintained in the control room. This status information sheet specifies which of the LPRM chambers in each APRM channel are inoperable or bypassed. If any of the APRM channels are inoperable or bypassed, this status sheet also specifies which additional LPRM chambers in the APRM channels may be bypassed or made inoperable without violating the requirements of plant technical specifications 3.1.B or 3.1.C and which APRM channel may not be bypassed above

61% of rated power. Operating Procedure 202.1, Rev. 20, "Power Operations," also requires that core daily checks be performed to indicate inoperable or bypassed LPRMs that are input to the APRM system and to document this information on form 202.1-1.

The inspector reviewed Standing Order 21 to ensure the status information sheet maintained in the control room covered the inoperable LPRM status and had been properly approved. The inspector also reviewed the "core daily checks" (form 202.1-1) performed on December 9, 1991, to ensure the LPRM status was accurately reflected and met the technical specification requirement. The inspector concluded that the licensee was properly implementing technical specification requirements 3.1.B and 3.1.C.

## 2.0 RADIOLOGICAL CONTROLS (71707)

During entry to and exit from the RCA, the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. Posted extended Radiation Work Permits (RWPs) and survey status boards were reviewed to verify that they were current and accurate. The inspector observed activities in the RCA and verified that personnel were complying with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area.

## 3.0 MAINTENANCE/SURVEILLANCE (62703,61726,71707)

### 3.1 Containment Spray Drywell Injection Valve Maintenance

During the NRC motor-operated valve (MOV) inspection (see Inspection Report Number 50-219/91-81), a considerable amount of grease was found leaking from the Limitorque actuator on containment spray drywell injection valve V-21-11. This operator was installed in the plant during 1986. The licensee replaced the operator with a new one and disassembled the old operator in the shop to inspect the internals and troubleshoot the leakage. Job order number (JO#) 34052 and work request number (WR#) 755846 were prepared to do this work.

A considerable amount of grease was found in the spring pack assembly and some grease separation was noted. Hardened grease was found along the walls of the main gear box. No indication of wear or scoring was noted in the drive sleeve bearings, worm or worm gear. The grease in the limit switch cartridge and gear box was hardened. The licensee concluded that these findings did not affect the operability of the operator.

The inspector observed part of the actuator disassembly and reviewed the licensee's inspection results and corrective actions. At the next available opportunity, the licensee plans to inspect other Limitorque actuators installed in the plant which were procured under the same shop order. The licensee also plans to replace a 1984 vintage Limitorque actuator at the next available opportunity and perform the same inspection. The results of the inspection were factored into the licensee's grease report (see section 3.2).

The inspector reviewed the work package. The licensee indicated that the vendor recommended spring pack modification (re: Limitorque Maintenance Updates 88-2 and 90-1 related to spring pack hydraulic lock) was partially implemented. The inspector did not find any documentation regarding this modification, nor was an engineering evaluation included in the work package. The licensee indicated that existing controls required a review by Plant Engineering for applicability before the maintenance updates were included in the vendor manual and that they were in the process of determining whether the other two recommended modifications should be incorporated. The job order package was left open pending this determination, additional work as required, and grease addition to the removed actuator. Upon completion of the work order package, the removed actuator will be considered a spare actuator and will be returned to storage for future use. The licensee indicated that the installed modification would be captured i 'S2 documentation and the work authorization approved document list. Plant Engineering will be informed by memorandum so that the database can be updated.

Regarding the installation of the Limitorque recommended spring pack modifications to other actuators, the licensee indicated that a determination would be made by February 1, 1992, after a review of previous MOV data. To date, no incidents of spring pack hydraulic lock have been identified at Oyster Creek. Implementation of the spring pack modification would be coordinated with other Generic Letter (GL) 89-10 followup efforts.

The inspector concluded that the disassembly of the subject actuator was done following approved procedure and the personnel involved in the disassembly and inspection had adequate understanding of the procedure. The inspector will continue to follow the licensee's determination on the implementation of the spring pack modification and the close out of the V-21-11 work package.

### 3.2 Motor-Operated Valve Maintenance Program

NRC review of the Oyster Creek motor-operated valve (MOV) grease inspection report and the grease leakage identified by the NRC on V-21-11 and various other MOVs during the October 1991, MOV inspection, resulted in a question of the adequacy of the licensee's MOV maintenance program in this area. The NRC also questioned the lack of a periodic overhaul program. GL 89-10 recommended various improvements in licensee MOV programs and also identified various known operator grease problems. The GL recommended schedule for completion of followup actions was within five years or three refueling outages, whichever was later.

A technical analysis of 95 grease samples collected from various Limitorque actuators during the 13R outage indicated contamination of Exxon Nebula EP1 grease (calcium based) with Mobil Mobilux EP2 (Lithium based) (Report No. 53193-91-1642, Rev. 0, dated July 8, 1991). These two types of greases are incompatible. According to the vendor recommendations, mixing should be avoided, to prevent grease structural changes from occurring.

To verify the results, the licensee performed additional grease sampling and tests. The results of these tests confirmed the existence of mixed grease. Additionally, the licensee performed a review of historical information on MOV performance at Oyster Creek, including the inservice test (IST) and motor-operated valve analysis and test system (MOVATS) test results and machinery and work-order history. This review found the following weaknesses in the licensee's current MOV maintenance program:

1. No grease inspection was done on certain MOVs since 1981 or 1984; however, the licensee inspected the MOVs in the reactor building after the NRC's MOV inspection and concluded that no indication of gross grease leakage from MOVs was seen. The licensee also stated that no gross grease leakage from MOVs inside the drywell was observed during 13R.

2. The adequacy of grease samples as true representation of the grease condition was questioned. The licensee found that not all grease sample points had been used during the sample collection.

3. In some cases, grease samples were not sent to the laboratory for analysis.

4. The licensee's preventive maintenance procedure does not require stroking the valve or removal of the stem dust cap while applying stem lubrication. In some isolated instances MOV valve stems were not getting cleaned and lubricated when preventive maintenance tasks were performed; however, the licensee indicated that their MOVATS procedure required stem lubrication before data were acquired and valve stroking during testing, so all actuators were lubricated at least during or after 1986. This method, however, prevents acquiring as-found MOVATS data.

5. Documentation of preventive maintenance and laboratory results on grease inspection for V-5-166 was inconsistent

6. Consistent application of Exxon Nebula EP1 grease in the gear box, Mobil 28 in the limit switch gear case and Superlube as stem lubricant has not been ensured. Current maintenance procedures and tasks do not reflect the grease or lubrication the licensee considers the best to use.

7. The NRC and licensee's walkdown results indicated a need to develop a more comprehensive maintenance program with periodic overhaul requirements.

The licensee concluded that none of the MOVs were located where a grease separation condition had affected operability. However, the licensee determined that a comprehensive maintenance plan was needed to better define appropriate maintenance requirements, both for installed operators and operators in storage, the required overhaul frequency, requirements for as-found MOVATS signature before any activity requiring a full MOVATS test as preventive maintenance, and schedule drywell MOV inspections at a target of opportunity during cycle 13. The licensee plans to complete these corrective actions by March 31, 1992. At the end of the inspection period, the licensee was developing a schedule for future MOV inspections.

The inspector reviewed the licensee's grease analysis reports, summary report of the licensee's analysis of grease inspection results performed after NRC MOV inspection, and interviewed various maintenance personnel. The inspector also concluded that the Limitorque actuator maintenance program needed considerable improvement and the licensee's planned corrective actions appeared to be appropriate by addressing the problem areas. The inspectors will verify the licensee's corrective action implementation.

### 3.3 Emergency Service Water Flow Instrumentation

On December 12, 1991, the inspector observed the removal and cleaning of the emergency service water (ESW) system I flow sensing element (Annubar) and the calibration of the ESW system I flow gauge. The work was being performed using an immediate maintenance job order number (JO# 35835). The maintenance was required when the ESW pump 52A differential pressure was found in the inservice test (IST) required action range during a routine surveillance test. Historically, the annubar flow sensing element has become fouled, resulting in an indication of degraded pump performance.

The removed Annubar was found to be relatively clean and free of biological growth. Only minor traces of a sand-like material were flushed out of the Annubar when cleaned with water. Both the high pressure and low pressure sensing ports on the Annubar were free from blockage.

After the Annubar was reinstalled, the instrument and control (I&C) technicians calibrated the ESW system I flow gauge. The gauge's as-found conditions were acceptable. No adjustments were made to the instrument.

The cause of the low developed differential pressure was determined to be degraded pump performance. ESW pump 52A was replaced with a new pump and successfully retested. The removed pump has not yet been disassembled; however, the pump had been in service for about six years without any significant maintenance. Previously, in November 1991, ESW pump 52B had failed its IST surveillance and the degraded performance was attributed to normal pump wear. ESW pump 52B was completely rebuilt.

It appears that both pumps failed their IST surveillances due to normal pump wear. The adequacy of the preventive maintenance (PM) program for the ESW pumps to prevent this common mode failure requires further licensee review. NRC review and evaluation of the ESW pump preventive maintenance program will be conducted in conjunction with the evaluation of the improved PMs for rotating equipment currently under development by the licensee.

The inspector reviewed JO# 35835; observed the Annubar removal and re-installation; and observed the calibration of the ESW system 1 flow gauge. The I&C technicians were knowledgeable about the job package requirements; all the maintenance and test equipment was in current calibration; and overall control of the work was adequate. The group shift supervisor (GSS) and an I&C group supervisor were seen observing the work. The inspector concluded that the maintenance performed on the ESW system 1 Annubar and flow gauge was adequately conducted and controlled.

### 3.4 Diesel Fire Pump Function Test

On November 20, 1991, GPUN conducted surveillance procedure 645.6.012, revision 8, "Fire Pump Functional Test," on the 1-2 diesel fire pump. The two redundant diesel fire pumps are four stage, deep draft, Layne and Bowler Incorporated, model Fi6EH-4 pumps. The surveillance was being performed to allow plant engineering, operations, and maintenance to evaluate the pump performance after the 1-2 diesel fire pump failed the surveillance and was declared inoperable on November 15, 1991. The pump did not develop the required flow rate of 2000 gpm at a pump discharge pressure of above 100 psig.

During the test on November 20, the pump discharge pressure response was the same as noted during the November 15 test. With plant maintenance, operations, and engineering present, the performance of the diesel engine and the system relief valve was determined to be acceptable. The licensee determined that degraded pump performance had resulted in the failure of the 1-2 diesel fire pump to develop the required flow and pressure.

The group shift supervisor (GSS) was informed of the failure and directed that the surveillance be secured. The fire water supply system was returned to a normal standby configuration. Diesel fire pump 1-2 remained inoperable.

The inspector observed the performance of surveillance procedure 645.6.012, on November 20, 1991, and reviewed the completed portion of the surveillance procedure. Overall, control of the surveillance was good. Communication between the control room operators and the on-scene operators was good. The GSS's decision to secure from the surveillance was appropriate. Required data were recorded in the procedure and the point at which the surveillance was secured was adequately documented. The inspector viewed the cooperation between plant maintenance, operations, and engineering as an improved effort in the development of work instructions to perform corrective maintenance.

When the pump assembly was removed from the fire pond intake area, a rag was found lodged in the pump inlet. A similar problem was encountered with the 1-2 diesel fire pump in 1988. The rags, on both occasions, were apparently drawn into the pump inlet through an approximately $^1/_2$ inch gap between the pump housing and the inlet screen housing. To prevent this from recurring, the licensee fabricated two $^1/_8$ inch thick, stainless steel rings and installed the rings between the pump housing and the inlet screen housing, filling the gap.

The installation of the metal rings was controlled as a corrective change in accordance with procedure 124.2, revision 3, "Control of Plant Engineering Directed Corrective Changes and Modifications." A corrective change is a minor physical change to a component that does not change overall function or performance, and does not fall outside the established design envelope, as determined by an engineering evaluation. The corrective change must be controlled using a work package (job order, etc.); have a safety determination/evaluation performed; materials evaluated against original design specification and meet or exceed the quality standard of the original material; and the changes incorporated into existing documentation (vendor's manual, drawings, etc.)

The pump was disassembled and inspected. New bearings were installed and the pump was reassembled in the fire pond intake area. The inspector observed the disassembled pump, reviewed the job package (JO# 35251); reviewed the engineering instructions (P.E. File No. 1089-91) for installing the metal rings; discussed the method for installing the ring with plant maintenance personnel; and reviewed procedure 124.2, revision 3. No damage to pump internals (inlet plenum, impellers, or fixed vanes) was noted by the inspector. The job package contained adequate instructions for the removal, repair, and reinstallation of the pump. Adequate instructions were provided to control the installation of the metal ring between the pump housing and the inlet screen housing by plant engineering personnel. The addition of the two stainless steel rings was adequately documented and controlled as a corrective change to the 1-2 diesel fire pump in accordance with procedure 124.2. Post-maintenance testing was satisfactorily completed and the 1-2 diesel fire pump was restored to an operable status on December 12, 1991.

### 3.5 Standby Liquid Control Operability and Inservice Test

On November 26, 1991, the inspector observed the performance of surveillance procedure 612.4.001, "Standby Liquid Control Pump and Valve Operability and Inservice Test," and the concurrent performance of an inservice hydrostatic test on the pump discharge piping. The purpose of this surveillance was to verify the operability of the standby liquid control (SLC) pumps and to satisfy the inservice test (IST) requirements for the SLC pumps and pump discharge check valves. The IST on the pump discharge piping was performed to meet the 10 year IST requirement.

The inspector observed the performance of the surveillance procedure for both SLC pumps A and B. The inspector observed the performance of procedure prerequisites, including the initial system valve lineup. Both pumps satisfactorily started and operated at the specified pressure.

Proper flow was developed by both pumps for the given discharge pressure. Correct pump rotation was verified for both pumps. During performance of the pump IST, pump vibration data was correctly obtained and recorded. Pump discharge check valve IST requirements were met by noting that each pump developed the required flow. After completion of the surveillance procedure, the inspector observed proper system restoration, including performance of the return to service valve lineup.

During performance of the operability check and IST for SLC pumps A and B, the non-destructive examination and inservice inspection (NDE/ISI) group performed a hydrostatic test on the pump discharge piping. This test was completed satisfactorily with two minor leaks noted. An approximately eight-drop-per-minute leak occurred on the SLC pump B discharge flange. This flange may have been leaking for some time, as evidenced by a buildup of boron precipitation on the flange joint. The other leakage was minor packing leakage on the recirculation line isolation valve V-19-23. Both leaks were noted by the NDE/ISI group and forwarded to engineering for evaluation. The flange was tightened to stop the leak and the minor packing leak was left as-is.

The inspector reviewed the surveillance procedure and verified that the operators were complying with the procedure and properly documenting test data. Pump flows were verified to be between the low and high alert range. Pump vibration was verified to be below the alert range. Good communications were observed between the operators and the control room, with the operators ensuring that the control room was kept informed of impending SLC pump starts and stops. Good communications and coordination were also observed between the operators and the NDE/ISI group during the pump discharge piping hydrostatic test. The surveillance procedure was clearly written and easy for the operators to follow. No problems were identified during performance of this procedure.

### 3.6 Drywell Sand Bed Removal Project

On November 29, 1991, GPUN began removing the sand between the steel drywell (DW) liner (primary containment pressure boundary) and the concrete shield wall. The sand was located below the torus downcomers, between elevations 12 feet 3 inches and 8 feet 11¼ inches, in a gap about 15 inches wide around the circumference of the steel DW liner. Accelerated corrosion of the DW liner had occurred due to water intrusion into this area. With water in the sand bed region, a galvanic cell was created between the liner and the rebar in the shield wall. GPUN has attributed the intrusion of water to small flaws in the steel liners of the equipment storage and refueling cavity pools. These flaws allowed water to seep into the annulus between the steel DW liner and the concrete shield wall, collecting in the sand bed region. Normally, both the equipment storage and refueling cavity pools are drained. However, during a refueling outage, the pools are filled with water, primarily to provide shielding. During the 12R and 13R refueling outages, both pools were coated with a rubberized strippable coating that effectively stopped the water intrusion into the annulus between the DW liner and shield wall.

The licensee's analysis of the DW steel liner supports operation until the next refueling outage (14R). Ultrasonic (UT) thickness measurements are being made on critical areas of the DW liner (containment) during each refueling outage and outages of sufficient length to permit containment entry. NRR and the Region are following the licensee's engineering efforts. Additional analyses were performed by General Electric (GE) and Teledyne to support removal of the sand bed and the use of ASME Section III vice Section VIII for allowable wall thickness. Results of the UT measurements during the 13R refueling outage indicated a decrease in the corrosion rate. Based on this, the licensee expects to justify operation beyond 14R. GPUN has submitted those analyses for NRC review.

To remove the potential for further galvanic corrosion, GPUN decided to remove the sand from the sand bed area. To perform the sand removal, GPUN obtained a high-efficiency, diesel-powered, vacuum system manufactured by Vacuum Engineering Corporation. The vacuum system was originally designed for asbestos removal and provided good control features for the removed sand. The diesel vacuum was setup in the reactor building truck bay airlock. The vacuum hose, diesel exhaust hose, and a truck bay high efficiency particulate air (HEPA) filter unit exhaust were routed through the inner truck bay manway to a reactor building exhaust duct. Each of the hoses was fitted with a quick disconnect fitting by the truck bay manway to allow the manway to be closed quickly if needed to restore secondary containment integrity in the event that the outer truck bay door (secondary containment boundary) was breached.

By December 13, 1991, the licensee had removed about nine 55 gallon drums (7.5 cubic feet per drum) from one of the 10 bays where sand will be removed. A total of 140 drums of sand are planned for removal, 14 from each bay. The licensee has begun using an auger to break up compacted sand to allow the vacuum to remove it. The use of an auger was one of the contingency plans the licensee had developed if compacted sand was encountered.

The inspector has observed operation of the diesel vacuum and observed video taped portions of the sand removal. The inspector verified the installation of the quick disconnects for the vacuum hose, diesel exhaust hose, and HEPA unit exhaust hose. Requirements for control of the hoses passing through the reactor building truck bay manway and the temporary variations used to install the diesel vacuum and HEPA unit were reviewed by the inspector. The progress of sand removal and contamination levels of the sand were discussed with GPUN personnel. Radiological controls and sand sample results were reviewed by the inspector.

Overall, the sand removal project was being adequately controlled. A minor discrepancy with the control of the HEPA unit exhaust hose quick disconnect was corrected by the licensee before placing the unit in service. Preliminary sample results of the sand indicate cesium 137 (Cs-137) and cobalt 60 (Co-60) contamination (Cs-137: $3 \times 10^{6}$ to $3 \times 10^{5}$ uCi/gram and Co-60: $1 \times 10^{7}$ uCi/gram). Radiological controls were adequate and the sand was being treated as low specific activity (LSA) radioactive material. The resident staff will continue to follow the progress of sand removal.

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

### 4.1 Primary Containment Venting and Purging Issue

During the annual emergency exercise on October 22, 1991, a simulated plant condition was presented which brought out apparent inadequacies in the combustible gas control guidance in the emergency operating procedures (EOPs). In particular, the exercise scenario presented the players with a simulated highly explosive gas mixture in the torus airspace (18% hydrogen and 20% oxygen). Emergency Operating Procedure, EMG-3200.02, "Primary Containment Pressure and Hydrogen Control," was used to effect venting and purging of the torus airspace. Simulated venting of the torus volume through the standby gas treatment system was accomplished; however, simulated purging had not commenced (before the end of the exercise) because technical support personnel had determined that procedural instructions for purging the torus volume with air would not have worked. The EOP directed purging operations to be performed in accordance with Procedure 312, "Reactor Containment Integrity and Atmosphere Control," Rev. 56, dated October 21, 1991.

After the exercise, GPUN took prompt action to evaluate the potential procedure inadequacies. On October 25, 1991, the control room operators were provided interim guidance to purge the drywell and/or the torus with nitrogen (not with air) using Procedure 312, Section 16.0, whenever EOP EMG-3200.02 was being used. The interim guidance also directed the operators to direct the purge through the standby gas treatment system (SGTS) only at pressures below 0.5 psig to prevent potential damage to the SGTS filters.

Concurrently, the GPUN technical functions department performed a detailed evaluation to determine the best method for venting and purging the primary containment under conditions of fuel damage resulting in hydrogen generation, as well as other venting and purging guidance directed by the EOPs. Additional concerns were recognized and were addressed by the evaluation. The most significant results of the evaluation are summarized below.

The normal containment air supply system and its ductwork are not capable of handling pressures in excess of 0.2 psig. Therefore, at drywell pressures above atmospheric, use of the air supply system to effect purging would result in the potential failure of the ventilation duct and a probable ground level release. The supply fans do not have sufficient head to overcome the water level in the torus downcomers and would not have allowed purging of the torus through the SGTS with a combustible gas mixture (as presented during the exercise scenario). While an air purge of the torus is possible through manually opening the reactor building to torus vacuum breakers, purging of the torus volume into the reactor building is not desirable. The evaluation concluded, therefore, that nitrogen should be used exclusively for purging either the drywell or the torus for combustible gas control.

At pressures greater than 0.6 psig, the SGTS filters could be damaged, reducing their filtration capability. To preclude this damage and provide for the most effective use of SGTS, the EOPs have been changed to permit the use of exhaust fan EF 1-5 to initially vent containment when a pressurized or potentially explosive condition exists. The exhaust fan would be used until the condition which could damage the SGTS filters no longer exists. Since the exhaust fan flow rate (70,000 cfm) is considerably greater than the design flow of SGTS (2,600 cfm), the use of the exhaust fan will promote quicker use of SGTS by rapidly reducing any pressure and/or by reducing the amount of hydrogen in containment. Use of the exhaust fan will ensure negative pressure in the reactor building, even if the ventilation ductwork should fail. This will ensure, however, an unfiltered stack release. An unfiltered stack release under these conditions is consistent with BWR Emergency Procedure Guidelines (EPGs) to vent containment irrespective of radioactive release rate, if containment integrity is threatened.

The inspectors reviewed the temporary procedure changes which were implemented on December 10, 1991, as a result of these evaluations, and found that the changes were acceptable and provided comprehensive guidance, within the EOPs themselves, for primary containment venting and purging operations. Procedure changes are also being developed for the normal operating procedure 312.

On December 11, 1991, GPUN made a four-hour NRC notification after evaluating the results of the engineering evaluation, noting that they had identified a condition which could have resulted in a ground level release and failure of the SGTS under accident conditions. However, after further review, GPUN retracted the four-hour notification on December 13, 1991, noting that while the simulated conditions were within the scope of the EOPs, they were considerably outside of the design basis of the plant. No Licensee Event Report (LER) will be submitted on this issue.

The inspectors concluded that GPUN was responsive to the deficiency identified in the procedure and method for purging the drywell and torus discovered during the annual exercise. After the deficiency was identified, the licensee quickly provided interim guidance to the control room operators. The licensee thoroughly reviewed the purging issue and was timely in developing the necessary changes to the EOPs. Based on the subsequent engineering evaluation the licensee conservatively made the four-hour NRC notification. Overall, the inspectors concluded that the licensee's response was very good in resolving the purging concern of the drywell and torus.

**4.2 Technical Support Center Ventilation System**

GPUN identified several problems with the ventilation system for the technical support center (TSC). During a system test on November 25, 1991, performed by Nuclear Consulting Services (NUCON), discrepancies were noted with system flow and the system's filter train. The system contains an air handling unit (AHU) designed to produce about 2030 cfm flow. About 100 cfm is routed to a computer room and the remaining 1930 cfm is supplied to the TSC. Air is drawn into the system from the TSC (about 1240 cfm) and from an outside air intake (about 790 cfm). The outside air makes up for losses from the TSC and the computer room. The air is drawn through the filter train or allowed to bypass the filter train using dampers. In the filter train are post- and pre-charcoal bed high efficiency particulate air (HEPA) filters, a train pre-filter, a charcoal adsorber, and a charcoal bed fire suppression system. These elements along with the associated duct, dampers and system control switch in the TSC, makeup the TSC ventilation system.

Deviation report number (DR No.) 91-953, documented that during the November 25, 1991, test that system flow was less than design (only 85%); testing of the charcoal bed could not be performed due to improper packing of the charcoal sample canisters (excessive settling of the charcoal); the leak test on the charcoal bed failed (Halide penetration of 3% to 4.3%); and that the charcoal bed fire suppression system may not have been adequately installed (fire detection heat sensor located upstream of the charcoal bed). A second DR (No. 91-961) was written on December 6, 1991, documenting additional concerns with the design and testing of the TSC ventilation system. DR No. 91-961 stated that the system does not contain a duct radiation monitor and that the system had not been tested to demonstrate its ability to maintain a positive pressure in the TSC. Both the duct radiation monitor and the ability of the system to maintain a positive pressure (+1/8 inch water gauge) were included in the system design description (SDD) 169A, section 6.4.3.3. In addition SDD 169A, revision 1, indicated that the system shall be designed to meet the requirements of Standard Review Plan 6.4 as applicable with respect to NUREG 0696, "Functional Criteria for Emergency Response Facilities," and General Design Criterion 19, "Control Room," of 10 CFR Part 50, Appendix A.

Based on the information in the two DRs, the licensee has begun a design review of the system. The function of the ventilation system is to help maintain a habitable environment in the TSC during accident conditions, including ensuring the air supply is filtered when radiation is present. The inspector questioned the licensee on the ability of the TSC ventilation system to maintain habitability in the TSC during accident conditions.

The licensee performed a simplistic comparison of the TSC ventilation system and the control room ventilation system. Both systems are required to maintain a habitable environment during accident conditions. This comparison concluded that since the control room ventilation system met the habitability requirements for Beta and Gamma radiation doses without any emergency filtration and a normal infiltration rate of 2000 cfm (analyzed up to 14,000 cfm), the TSC ventilation system meets the same habitability criteria since the TSC infiltration rates are lower (790 cfm). On this basis the licensee determined that the TSC ventilation system was operable and would adequately maintain TSC habitability. The inspector concluded that the simplistic comparison between the TSC and control room ventilation systems and the ability of the TSC ventilation system to maintain a slight positive pressure (in the TSC) provided sufficient justification for the licensee to determine that the TSC ventilation system was operable. As additional information becomes available on the TSC ventilation system design, the inspector will review the documentation to assess continued operability of the system.

The inspector reviewed the following information:

1. NUREG 0737, Supplement 1 — Clarification of TMI Action Plan Requirements

2. NUREG 0696 — Functional Criteria for Emergency Response Facilities

3. SDD 169A, revision 1 — Site Emergency Building Design

4. QDR 91-055

5. a September 30, 1987, memorandum from O. Perez, engineer, Plant Engineering to J. Kowalski, OC Licensing Manager, on the subject of SEB TSC ventilation system regulatory requirement

6. an October 20, 1987, memorandum from B. DeMerchant, licensing engineer to J. DeBlasio, Manager Plant Engineering, in response to the September 30, 1987 memorandum

7. an April 1, 1982, letter from P. Clark, Executive Vice President, to the Director Nuclear Reactor Regulation (NRR) on the status of Emergency Operations F[illegible]ies

Based on the inspector's review and discussions with GPUN personnel, the inspector was unclear as to how the licensee was meeting the requirements of NUREG 0737 with regard to TSC habitability.

The inspector was also concerned with the maintenance and testing history of the TSC ventilation system. Section 50.47.(b)(8) of 10 CFR Part 50 requires that adequate emergency facilities and equipment to support the emergency response are provided and maintained. When the inspector questioned the licensee on the maintenance and testing history of the TSC ventilation system, the only documented information that was available was that a test had been performed by the startup and test (SU&T) department in December 1987, and the November 25, 1991, test data. Discussions with GPUN personnel indicated there appeared to have been no maintenance performed on the TSC ventilation system.

The licensee has committed to providing the inspector with documentation on how the requirements of NUREG 0737 for TSC habitability are being met. The issue on the design adequacy and maintenance practices for the TSC ventilation system will remain unresolved pending NRC review of the licensee's documentation on compliance with NUREG 0737 and 10 CFR Part 50.47 requirements (UNR 50-219/91-37-01).

**4.3 Ultrasonic Examination of Weld Overlay Repaired Stainless Steel Piping**

Inspection and Enforcement Bulletin 82-03 established an intergranular stress corrosion cracking (IGSCC) inspection program for use at BWR plants in The United States. The bulletin, additionally, established a qualification program for ultrasonic examination personnel responsible for performing the inspections at those plants. Bulletin 83-02 expanded the inspection program which resulted in the detection of IGSCC in most of the plants that performed examinations and extensive activity to replace or repair the cracked welds. A repair method was proposed incorporating the use of weld overlay and was approved by the NRC on a case-by-case basis as a short-term remedy. Improved techniques have been developed for the ultrasonic examination of the overlay repaired welds and the NRC has approved extended use of the repair based on the ability to monitor the existing IGSCC after the application of weld overlay.

The Electric Power Research Institute (EPRI) NDE Center at Charlotte, North Carolina, in conjunction with the BWR Owners Group, was instrumental in developing ultrasonic examination techniques which are capable of examining the weld overlay material and base material directly under the overlay. This permits the monitoring of existing IGSCC and its propagation, if that should occur.

This inspection was performed to ascertain whether the ultrasonic examination of weld overlay repaired welds at Oyster Creek agrees with the EPRI recommended technique.

The licensee's procedure, 6100-QAP-7209.29, Revision 0, permits the use of a calibration standard of a smaller diameter than the production weld provided the overlay thickness is within ± 0.250" of the original weld overlay repair. The procedure states that the uppermost determining factor in the selection of a calibration standard for this procedure is that the thickness of weld overlay shall coincide ± ¼" with that of the actual weld overlay repair under examination. Deviation from that requirement is permitted with the approval of a GPUN Level III examiner. Other sections of the procedure require that calibration block nominal diameter and overlay thickness be the same as that of the production weld.

The practice at Oyster Creek is different from the above in that a single 8" diameter calibration standard containing weld overlay 0.400" thick was used to examine welds of 8" and 26" diameter containing weld overlay ranging from 0.300" to 0.83" thick.

During a telephone conversation on December 12, 1991, with EPRI personnel, the inspector and licensee representative discussed the overlay ultrasonic examinations as performed at Oyster Creek. The EPRI personnel stated that their research and experience indicated that the calibration block and production weld should be similar in diameter, wall thickness, and overlay thickness. They further stated that during operator qualification examinations, EPRI uses calibration blocks of the same nominal diameter and thickness as the overlay repair under examination. EPRI suggested that the licensee determine the adequacy of using calibration standards containing weld overlay thinner than that on the production weld, and of smaller

At the exit meeting, the licensee committed to perform the study with the assistance of the EPRI NDE Center.

The ability to detect defects is dependent on establishing adequate test sensitivity from the calibration standard. Because of the discrepancy in calibration standard diameter and overlay thickness versus production weld characteristics at Oyster Creek, the adequacy of the examinations performed at the plant on weld overlay repairs is questionable. This item is unresolved pending completion of the licensee's study and NRC review of the results (50-219/91-37-03).

## 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 (40500)

### 6.1 Operator Concern Program

In response to Diagnostic Evaluation Team (DET) findings, GPUN proposed a number of activities intended to improve the area of operations' self-assessment. One of these activities was the continued implementation of the operator concern program. The operator concern program was implemented in March 1989 to provide a process for control room operators to formally document their concerns to operations department management. Since that time, approximately 1,000 operator concerns have been submitted. The majority of those concerns submitted to date have dealt with proposed procedure improvements, followed by equipment and hardware issues. The time to respond to each concern has varied with issue complexity and assigned priority.

The DET had commented that some operator concerns remained open for an extended period. GPUN has acknowledged this, but noted that initial problems with timeliness of resolution could be attributed partially to the large initial influx of concerns after the program began. The rate at which operator concerns are generated has stabilized and the backlog of open issues has been reduced.

Approximately 80% of the total number of operator concerns submitted to date have been resolved. The inspectors reviewed the remaining open operator concerns to assess issue content, prioritization, and timeliness of response. The inspectors found that valid concerns were being raised and that, for the most part, the author of each concern attempted to provide sufficient supporting information. Each concern is prioritized by operations management as either Urgent, Important, or Routine and submitted to an appropriate individual for resolution. The operations support manager then provides a memorandum to the author of the concern indicating his understanding of the issue and the individual to whom it has been assigned for resolution. The inspector concluded that reasonable efforts were being taken to resolve the concerns in a timely manner.

The inspector also reviewed the operator concerns to determine if any safety issues were involved. Of nearly 200 operator concerns reviewed, the inspector only made note of one which should have been brought to a higher level of review. Operator concern 90-060, dated March 7, 1990, noted a potential problem with the technical specification bases for the standby liquid control (SLC) system minimum injection time for the enriched sodium pentaborate solution. The concern referenced an August 27, 19[illegible], letter submitted to GPUN Technical Functions in Parsippany from General Electric regarding the SLC system injection rate. The GE letter provided a simple algorithm with which to calculate minimum injection time based on the Boron-10 isotope enrichment within the sodium pentaborate solution. Using the algorithm, a minimum injection time was calculated which was larger than that specified in the SLC technical specification bases (28.3 minutes vice 26 minutes). After further review, the inspector found that this same concern was submitted a second time by the same author (in December 1990) due to lack of response to the initial submittal. The author of the concern was then requested to submit the issue as a Preliminary Safety Concern (PSC) through the licensing department. The inspector reviewed the PSC response generated by the engineering and design department in Parsippany and concluded that the minimum injection time noted in the SLC technical specification bases was appropriate. The PSC response demonstrated that the minimum normal operating liquid poison tank volume assumed by GE in the algorithm was based on the old SLC technical specification and was incorrect.

While this issue was effectively resolved, the inspector noted that it was not reviewed for its safety implications in a timely manner. The operations support manager responded that the operator concerns are normally reviewed for application to the deviation report process and acknowledged that this issue should have been documented in that manner and evaluated accordingly. The operations support manager also noted that the most recent version of the Operator Concern Report form (dated September 1991) includes a check-off block for applying the issue to the deviation report process. The inspector verified the inclusion of this information on the form.

The inspector concluded that the operator concern program is working well, and that reasonable efforts are being made to provide timely response to both current and backlogged issues. The operators appear to have accepted the program and see it as a legitimate means to help improve their work environment. The program has recently been expanded so that other plant departments may provide input.

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

(Closed) Open Item 50-219/90-23-02. This item related to the calibration and control of measuring and test equipment (M&TE) used during post maintenance testing (PMT) of the number 1 emergency diesel generator (No. 1 EDG) batteries on December 6, 1990. The M&TE was a battery tester manufactured by Alber Engineering, Inc., model BCT-1000. The BCT-1000 displays and records individual cell voltages. The inspector had identified that the BCT-1000 had also been used on November 17, 1990, during a similar PMT of the No. 2 EDG batteries.

The inspector noted that the calibration for the BCT-1000 had expired in October 1990. After the inspector identified the overdue calibration to the licensee, a successful field calibration was performed on the BCT-1000 on December 6, 1990. Procedure A100-ADM-3053.01, revision 2, "Calibration and Control of Maintenance, Test and Inspection Tools, Gauges, and Instruments," requires each use of M&TE to be recorded in the equipment's usage record, and that M&TE shall not be used without a current calibration. However, in November and December 1990, uses of the BCT-1000 were not recorded in the BCT-1000 usage record at that time. Also, the BCT-1000 was used on November 17, 1990, without a current calibration.

Contributing to this event was the practice of storing the BCT-1000 in the electrical shop instead of in the calibration facility (Cal Lab) with other M&TE because of its size. After the inspector had identified the use of the BCT-1000 past its calibration due date, the licensee began storing the BCT-1000 in the Cal Lab.

The inspector discussed control of the BCT-1000 with the Cal Lab supervisor on November 26, 1991; reviewed the BCT-1000 usage record; observed the storage location for the BCT-1000; reviewed procedure A100-ADM-3053.01, revision 3; and reviewed various revisions of the following historical records of completed surveillance procedures for use of the BCT-1000:

| | |
|---|---|
| 626.2.001 | Main Turbine Emergency Lube Oil System Operability Test |
| 634.2.001 | Main Station Battery Discharge and Low Voltage Relay Annunciator Test |
| 634.2.007 | Main Station Batteries Service Test |
| 636.2.004 | Diesel Generator Battery Discharge (Load Test) and Low Voltage Annunciator Test |
| 636.2.012 | Diesel Generator Batteries Service Test |

During the review of the above procedures the inspector noted that the use of the BCT-1000 for testing of each system or component was not always documented in the test equipment usage record. The BCT-1000 had been provided to the Electrical Maintenance Shop for extended use during April 1991. Clear traceability on the use of the BCT-1000 in the test equipment usage record was not maintained. Failure to document each use of M&TE in the test equipment usage record continued to be a concern.

A similar concern on the traceability of M&TE used for maintenance activities was identified by the NRC during a maintenance inspection in November 1991 (see NRC inspection report number 50-219/91-34, section 2.5). As a result of this maintenance inspection concern, the GPUN Quality Assurance (QA) organization conducted audits and monitoring observations on the control of M&TE. These QA observations were documented in Operations QA Monitoring Reports, serial numbers 9121026 and 9121026A. The observed deficiencies were documented in Quality Deficiency Report (QDR) number 91-068.

The QDR 91-068 indicated a widespread failure to implement the requirements of procedure A100-ADM-3053.01 to ensure all surveillance and maintenance activities performed using a given piece of M&TE could be identified. In response to QDR 91-068, the Director, Plant Maintenance, indicated the following long term corrective actions have been planned:

1. Revise procedure A000-WMS-1220.08, "Job Order," to require the Job Supervisor to ensure M&TE used is recorded in the test equipment usage record.

2. Require job packages, or other work documents to be presented to Cal Lab/tool room personnel at the time instruments are issued.

3. Make required reading the November 27, 1991, Memorandum from L. Lammers on the subject of corrective actions in response to QDR 91-068 for appropriate supervisor/managers using M&TE.

4. Upgrade the computer based work management system (GMS2) such that computerized M&TE records in the Cal Lab will link to data on M&TE usage recorded in job orders.

As an interim corrective action, the job supervisors were required to ensure M&TE used during maintenance was documented in the test equipment usage record. In addition, the inspector has observed the implementation of Item 2 above on several occasions since December 9, 1991.

The inspector reviewed QDR 91-068; the two monitoring reports; and the memorandum from the Director Plant Maintenance in response to QDR 91-068, dated November 27, 1991. The corrective action discussed in the November 27, 1991, memorandum appeared appropriate to address the concern on the traceability of M&TE used during maintenance activities. However, the problem was originally identified by the NRC in December 1990, when the BCT-1000 was used during PMT on the No. 1 EDG. In addition, the test equipment usage record was not updated to reflect the November and December 1990 uses of the BCT-1000 until questioned by the inspector on November 26, 1991.

The GPUN Operational Quality Assurance (OQA) Plan and Regulatory Guide (Reg Guide) 1.33, revision 2, "Quality Assurance Program Requirements (Operation)," requires procedures be developed to control the use of M&TE. Paragraph 6.6.1.2.e of the GPUN OQA Plan requires that "methods for determining the validity of previous inspections performed when M&TE is found out of calibration" shall be established, and "inspection or tests are repeated on items determined to be suspect." To provide the traceability and control of M&TE needed to fulfill the requirements of the GPUN OQA Plan and Reg Guide 1.33, procedure A100-ADM-3053.01, paragraph 6.2.1, requires "only current calibrated equipment shall be used and all transactions shall be documented on the test equipment usage record." Paragraph 6.5.4 of A100-ADM-3053.01, stated, in part, that the test equipment usage record "will be used to identify the systems or components which were checked (using the M&TE) and provide the means for back-checking should any reason arise for a back-check."

The inspector concluded that while the licensee had regained control of the BCT-1000 with regard to the use of the instrument after its calibration due date, the failure to record each use of M&TE continued to be a problem and was contrary to the requirements of procedure A100-ADM-3053.01. The licensee's planned corrective actions in response to QDR 91-068 appeared to be appropriate to prevent recurrence of this event; the event was not reportable; and there has been no previous violation for which corrective actions addressed this issue. However, this issue was identified by the NRC on two separate occasions, in December 1990, and again in November 1991. As such, a Notice of Violation has been included in this report for the failure to implement the requirements of paragraph 6.2.1 of procedure A100-ADM-3053.01 and document each use of the BCT-1000 in the test equipment usage record (NV4 50-219/91-37-02). Open item 50-219/90-23-02 is closed with the issuance of this violation.

## 8.0 INSPECTION HOURS SUMMARY

The inspection consisted of normal, backshift, and deep backshift inspection; 32 of the direct inspection hours were performed during backshift periods, and 16 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 December 23, 1991. 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 an exit meeting for another inspection conducted as follows:

November 22 (Confirmatory Measurements) Report No. 50-219/91-36

At this meeting the lead inspector discussed preliminary findings with senior GPUN management. The resident inspectors also conducted a facility tour and attended a licensee presentation with the Regional Administrator, Region I, on November 14, 1991.

### 9.3 Unresolved Items

Unresolved items are matters for which more information is required to ascertain whether they are acceptable, violations, or deviations. Unresolved items are discussed in sections 4.2, 4.3, and 7.0 of this report.