U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	97-01
Docket No.	50-219 72-1004
License No.	DPR-16
Licensee:	GPU Nuclear Incorporated 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	January 13, 1997 - February 23, 1997
Inspectors:	Larry E. Briggs, Senior Resident Inspector Stephen M. Pindale, Resident Inspector
Approved By:	Peter W. Eselgroth, Chief Projects Branch No. 7

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 97-01

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers about a six-week period of inspection.

Plant Operations

- There were several weaknesses that resulted in a spill of about 250 gallons of water from a control rod hydraulic control unit. The weaknesses included a poorly prepared and untimely tagging request, the failure to use a print or diagram to verify proper system status and configuration, and the lack of independent verification or qualitative procedural acceptance criteria to verify that the tagging order was correct (01.2).

- A recent move of one of the onshift senior reactor operators to an area from which licensed operator and overall plant activities can be directly observed was a positive initiative by operations management to enhance oversight and control of control room activities (01.1).

- The operators and shift technical advisor were alert to identify and trend an unexplained flow rate reduction for the "B" reactor recirculation pump (01.3).

- General Office Review Board (GORB) meeting sessions in the areas of operations (status and significant events) and engineering were characterized by probing discussions. The GORB was constructively critical of station activities and was focused on plant safety (07.1).

- Station management's efforts to communicate work performance expectations were positive steps toward improving human performance (07.2).

Maintenance

- Routine maintenance and surveillance activities observed by the inspectors were conducted safely and in accordance with station procedures (M1.3).

- The licensee approached the planning and execution of dilution pump maintenance with a high level of safety. The installation of vibration monitoring sensors on the No. 1 pump was a positive first step to more actively monitor the performance of all the dilution pumps (M1.4).

- Cable replacement activities for the "E" reactor recirculation pump motor-generator set were completed without error. Personnel followed applicable instructions and engineering provided strong support to maintenance personnel. Conduit re-routing modifications were effectively implemented (M1.5).

- The licensee had properly addressed the two failures of Limitorque motor operators used in non-safety related applications. The licensee promptly verified that the facility had not used any of the non-Limitorque supplied operators in any safety application (M7.1).

- Maintenance personnel respondeu quickly and effectively to an occurrence in which the augmented offgas system building became radioactively contaminated due to an equipment failure (R1.2).

Engineering

- A large number of As-found Field Change Notices (FCN) had not received technical review and approval indicating prior weak management of the engineering change document process. The licensee's followup actions to their self-identification that a significant number of FCNs did not receive the appropriate technical review and approval were acceptable. No safety equipment deficiencies were identified in connection with these findings. (E1.1)

- The licensee had provided appropriate attention to the outstanding issue of whether relays for safety related applications were properly tested and monitored. A communication weakness resulted in not testing all in-stock relays. The subsequent conditional release for the installed relays was acceptable. Continued aggressive followup is warranted to achieve full resolution of this issue (E1.2).

- The licensee did not display a conservative approach in deciding to increase the amperage limits for the four remaining recirculation pump motor-generator (RPMG) sets following the trip of the "E" reactor recirculation pump (cable failure), resulting in an automatic trip of a second ("C") reactor recirculation pump. The licensee observed a minor amperage oscillation while increasing RPMG set speed, and they had recognized that an effective voltage regulator adjustment was not possible, particularly at higher RPMG set speeds. In addition, there have been prior and repeated RPMG set operational problems, and these RPMG sets play an important role in reactivity management. The resulting transient posed a challenge to control room operators (E2.1).

- An August 1995 safety evaluation, performed to support a December 1995 modification to remove from service the isolation condenser (IC) radiation monitors, was incomplete in that it did not recognize that the IC vent radiation monitors is a NUREG 0737 requirement. This is another, although dated, example of failure to conduct an adequate UFSAR review which the licensee is currently addressing programmatically for future safety evaluations. This additional example indicates the need to perform reviews of other previously completed safety evaluations to determine whether other commitments or UFSAR items had been overlooked. Additional information is necessary to determine whether the licensee is in conformance with NUREG Item 0737, and the issue is an unresolved item (E2.2).

- The licensee aggressively pursued the root cause for failed temperature switches in the main generator stator cooling system. They continued followup activities after switches demonstrated a sensitivity to temperature changes, and sent the defective switches to an independent laboratory for further analysis. They also took prompt and effective action to identify other switches in the plant that were of the same type and have initiated action to replace them (E2.3).

- System engineering promptly responded and began collecting additional data following an unexpected flow reduction in the "B" reactor recirculation pump flow rate in an attempt to identify the problem. However, since a problem was not identified, additional monitoring continued at the end of the inspection (01.3).

- Engineering provided strong oversight and support of the "E" RPMG cable replacement activities, including the design and rerouting of a section of conduit (M1.5).

<u>Plant Support</u>

- The licensee effectively implemented the radiation protection and security programs (R1.1).

- Radiation protection personnel promptly and appropriately responded to an event during which the augmented offgas building became radioactively contaminated due to an equipment failure (R1.2).

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Report Details

Summary of Plant Status

The plant operated at full power until January 24, 1997, when plant operators reduced power to 40% for main steam isolation valve quarterly surveillance testing (valve closure test). Reduced power operation (at about 63%) continued for various other planned maintenance activities until January 25, 1997, when full power operation resumed. On February 11, 1997, the "E" reactor recirculation (RR) pump tripped due to an associated 4160 volt motor supply cable failure. Subsequently, while increasing reactor power with the remaining four RR pumps, the "C" RR pump tripped on February 12, 1997, placing the unit in three loop operation, which is prohibited by plant technical specifications. Accordingly, a plant shutdown was promptly initiated per technical specification requirements. The "C" RR pump was restarted within about three hours, and the shutdown was terminated at approximately 74% power.

Reactor operation was increased to 98% (limited because of four loop operation) during the ongoing cable replacement activities for the "E" RR pump motor-generator set. The cable replacement and testing activities were completed on February 21, 1997. Reactor power was then returned to 100% and full power operation continued through the remainder of the inspection period.

I. OPERATIONS (71707, 93702, 40500)

O1 Conduct of Operations[1]

O1.1 General Comments

The inspectors conducted frequent reviews of ongoing plant activities and operations using the guidance in NRC inspection procedure 71707. The inspectors observed plant activities and conducted routine plant tours to assess equipment conditions, personnel safety hazards, procedural adherence and compliance with regulatory requirements.

Control room activities were found to be well controlled and conducted in a professional manner with staffing levels above those required by Technical Specifications. The inspectors verified operator knowledge of ongoing plant activities, the reason for any lit annunciators, safety system alignment status, and existing fire watches. The inspectors also routinely performed independent verification from the control room indications and in the plant that safety system alignment was appropriate for the plant's current operational mode.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

Since startup from the recent 16R refueling outage, one of the onshift senior reactor operators (SROs) was moved to a new location within view of the controls. Previously, no SRO was stationed within view of the controls, although the SRO office was within the control room area. This move was initiated by station and operations management in order to increase SRO direct oversight and control of both routine and non-routine activities. In addition, the move was an attempt to abate a recent adverse trend in the number of personnel errors, and to provide additional control room access control (traffic and distraction reduction). During periodic control room tours, the inspectors observed effective oversight and control of control room activities by both the SRO and the lead CRO.

The inspector observed some of the activities associated with the January 24 - 26, 1997, planned power reduction. In particular, control room activities while placing the "C" reactor recirculation pump were well controlled. A pre-evolution briefing was conducted by the control room SRO as per reactivity management practices. Operator distractions were minimized during the activity. Overall, the activity was very well controlled and executed.

O1.2 Tagging Error on Control Rod Hydraulic Control Unit **(Violation 97-01-01)**

a. Inspection Scope (71707)

The inspector reviewed the circumstances concerning an apparent tagging error that occurred on January 25, 1997, during the scheduled power reduction for maintenance and surveillance activities. The inspector reviewed the tagging order, schematics of the hydraulic control unit, and interviewed personnel involved. The valving error resulted in a spill of about 250 gallons of control rod drive (CRD) water (high quality condensate water) on the 23 foot elevation of the reactor building.

b. Observations and Findings

On Saturday, January 25, 1997, at about 1:00 a.m., when hydraulic control unit (HCU) 18-39 was being tagged out, it was reported to the control room that water was leaking from the HCU. The water was determined to be from the HCU vent valve (107 valve). The leak was isolated by operations department personnel wearing plastics to reduce the possibility of personnel contamination. There were no personnel contaminations as a result of this occurrence. The licensee determined, based on the sump pump run times, that about 250 gallons of water had leaked through the open vent valve. The water was directed into a floor drain and the area was mopped. The first gross swipe sample (area greater than 100 square centimeters) for contamination indicated 200 to 400 counts per minute above background. Following additional cleanup the area was less than 100 counts per minute above background with a gross swipe sample. The licensee's

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radiological controls field operations manager noted that the contamination level would have been less than 100 counts per minute on the first count if the standard 100 square centimeter swipe sample had been taken instead of the more conservative gross swipe sample.

During the discussions, operations personnel noted that the tagging request was received on January 24, 1997. The request asked for a standard outage and identified the component to be isolated as V-305-0101, which is the manual insert isolation valve to the control rod drive unit. The work description was to replace the solenoid on V-305-0118. This valve number conflict caused some confusion and resulted in a telephone call to the requestor. It was determined that the work to be performed was replacement of the solenoid on V-305-0118, not V-305-0101. It was also communicated during the telephone call that the HCU would be tagged out without cooling water supplied, and the solenoid valve would require electrical isolation.

Several discussions subsequently occurred between the operations crew concerning whether the HCU should be tagged out with or without cooling water. Operations ultimately decided to tag the HCU with cooling water supplied. When the tagging order was finally issued, the operator missed changing the position of V-305-0107 valve from open (cooling water not maintained) to closed (cooling water maintained) from the prior version of the tagging order. This resulted in a direct flow of control rod drive cooling water at about 1050 psig to the reactor building floor when the scram inlet and outlet pilot valves were de-energized in accordance with the tagging order. An additional complication was the fact that, as part of the isolation, the air supply to the scram pilot valves and the scram inlet and outlet valves was closed and prevented the repositioning of the scram inlet and outlet valves to stop the leak by re-energizing their pilot valves.

Additional discussions with operations personnel identified that a diagram had not been used to verify that the correct valves were being tagged, and the immediate supervisor or another operator did not verify that the tagging order was correct for the desired condition (isolated with cooling water maintained). In addition, a standard tagout exists in the computerized tagout system for valves. Electrical information must be manually added. However, a standard tagout was not used.

The inspector discussed this event with licensee management. The inspector noted several weaknesses. The lack of performing an independent verification of the tagging request was the most significant because a separate review may have identified this error. The licensee stated that the tagging procedure (No. 108.7, "Lockout/Tagout Procedure") had been revised several years ago to eliminate the second verification requirement in the preparation of the tagging order. The second verification was removed to shift the responsibility for determining the initial boundary requirements to the requesting party. That is, an accurate and properly reviewed tagging request by the requesting party, coupled with a separate review by the operator (tagging authority) while processing the tagging request, in effect, would constitute a second verification.

Discussions with control room operators indicated that most tagging requests require some modification prior to placement of tags. The need for control room operators to modify or correct tagging requests is a strong indicator that the responsibility for properly developing accurate tagging requests is not being assumed by the requesting party. Failure of the requesting party to provide a detailed and correct tagging request essentially makes the control room operator the requestor and verifier, thereby eliminating a second check.

The inspector noted that in accordance with procedure 108, "Equipment Control," placement of tags does require an independent verification. That was done in this case. However, since the tagging order was incorrect, the independent verification of the tagout execution would not have prevented this occurrence.

c. Conclusions

The inspector concluded that there were several weaknesses associated with this occurrence: 1) the tagging request was poorly prepared and did not adequately specify the number and placement of tags, 2) the tagging request was not submitted until the day that the power reduction was scheduled to take place and operations personnel were somewhat focused on power reduction activities, 3) the standard tagout was not used as a starting point, 4) the tagging authority did not use a print or diagram to verify proper system status and configuration, and 5) there was no independent verification or qualitative requirement to verify that the tagging order was correct. Failure of procedure 108.7 to establish controls that ensure activities affecting quality are satisfactorily performed is a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." **(VIO 50-219/97-01-01)**

O1.3 "B" Reactor Recirculation Pump Flow Fluctuations

a. Inspection Scope (71707, 37551)

On February 20, 1997, control room operators and the shift technical advisor (STA) noted that the "B" reactor recirculation (RR) pump flow had decreased over about a 21 hour period. The inspector reviewed the associated trend graphs and deviation report, and monitored the licensee's followup actions.

b. Observations and Findings

Control room operators record individual RR pump flows every four hours. On February 20, 1997, the plant was in four loop operation due to the inservice cable failure on the "E" RR pump (Section M1.5 of this report). Individual flows for the four RR pumps were between 36,000 gpm and 37,500 gpm. A control room operator noted a slight change in the gross numbers obtained from control room indicators, and notified the STA to request retrieval of additional data. The STA obtained graphs for the four operating RR pumps for the period 12:00 a.m. to 9:00 p.m. on February 20, 1997. The resulting computerized plot identified a reduction in total RR flow rate of about 750 gpm between 5:00 p.m. and 6:00 p.m., and a total reduction of about 1300 gpm over the entire 21 hour period. Trend plots of the individual RR pumps identified the reduction to be attributed to the "B" RR pump. Other system parameters remained normal and stable.

The STA documented the condition in a deviation report. System engineering was informed of the identified condition and was requested to commence a review. Additional data was collected and reviewed. The data indicated that the "B" RR pump speed signal became "noisy" during the time of reduced RR flow. That is, the peak-to-peak band in the speed signal, that normally is about 0.2 Hz, increased to about 1.0 Hz (peak-to-peak band) while flow was reduced. After flow returned to normal, again without operator action (around 11:30 p.m. on February 20), the speed signal band returned to 0.2 Hz. The speed signal and RR pump flowrates were monitored for several days. By the end of the inspection, no additional anomalies had occurred. The licensee was continuing to monitor and evaluate data, and they were considering to plan a tachometer replacement during the next on-line maintenance window.

c. Conclusions

The operators and STA were alert to identify and trend the observed flow reduction for the "B" RR pump. System engineering promptly responded and began collecting additional data in an attempt to identify the problem. However, since a problem was not identified, additional monitoring continued at the end of the inspection.

O7 Quality Assurance in Operations

O7.1 General Office Review Board Periodic Meeting

The inspectors attended portions of the bi-monthly General Office Review Board (GORB) meeting that was conducted at Oyster Creek on February 5 and 6, 1997. This GORB meeting was a combined Oyster Creek/Three Mile Island committee meeting. The inspectors attended sessions presented to the GORB in the areas of operations (status and significant events) and engineering. The inspector concluded that the board's discussions were probing and constructively critical of station activities, and were focused on plant safety.

O7.2 Employee Group Meetings

On January 20, 1997, the Vice President/Director, Oyster Creek and the President, IBEW Local 1289 issued a memorandum to all Oyster Creek employees to advise them of a series of upcoming employee meetings whose focus would be on improving human performance at Oyster Creek in the wake of the results of recent industry and regulatory reviews and evaluations.

The inspector attended one of the meetings on January 30, 1997, which was well-attended. A one-page handout was provided to all attendees that addressed safe work practices, employee accountability and learning from mistakes.

The inspector noted that, although the presenters provided sufficient focus on safety, human performance and accountability, much of the employee concern centered on the financial and operational future of Oyster Creek. In addition, several of the attendees expressed concern that attendance for these meetings was optional. The VP/Director, Oyster Creek responded that the material presented and discussed would be incorporated into required employee training, thereby exposing all employees to the subject matter.

The inspector concluded that licensee senior management's efforts to communicate work performance expectations was notable. However, much of the discussion shifted away from worker performance to other matters.

O8 Miscellaneous Operations Issues

O8.1 Periodic Report Review

The monthly operating report for January 1997 was reviewed and found to be acceptable.

II. MAINTENANCE (61726, 62707, 90712, 92902)

M1 Conduct of Maintenance

M1.1 Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed selected maintenance activities on both safety-related and non-safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. The inspectors observed all or portions of the following job orders (JO):

- JO 513365, "Investigate Vibration for No. 1 Dilution Pump"
- JO 513839, "Replace Cable on "E" Recirculation Pump Motor Generator Set"
- JO 512916, "Remove Double Blade Guides From Fuel Pool"
- JO 511552, "Core Spray System 480 Volt Breaker (N203B) Preventive Maintenance"

b. Observations and Findings

The inspectors concluded that the above activities had been approved for performance and were conducted in accordance with approved job orders and applicable technical manuals and instructions. Personnel performing the activities were knowledgeable of the activities being performed and were observing appropriate safety precautions and radiological practices.

M1.2 Surveillance Activities

a. Inspection Scope (61726)

The inspectors performed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. They verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations. The inspectors reviewed portions of the following surveillance tests/procedures:

- 609.4.001, "Isolation Condenser Valve Operability and In-service Test"
- 617.4.002, "Control Rod Drive and Flow Test"
- 602.3.004, "Electromatic Relief Valve Pressure Sensor/Pilot Control Relay - Test and Calibrate"
- 636.4.003, "Diesel Generator Load Test"

b. Observations and Findings

A properly approved procedure was in use, approval was obtained and prerequisites were satisfied prior to beginning the test. Surveillance test instrumentation was properly calibrated and used, radiological practices were adequate, technical specifications were satisfied, and personnel performing the tests were qualified and knowledgeable about the surveillance test procedure.

M1.3 Routine Maintenance and Surveillance Activities Conclusions

The maintenance and surveillance activities observed by the inspectors were conducted safely and in accordance with station procedures.

M1.4 Licensee Investigation of No. 1 Dilution Pump Vibration

a. Inspection Scope (62707)

The inspector attended the diver pre-briefing and observed portions of the dive conducted on February 4, 1997, to inspect the No. 1 dilution pump.

b. Observations and Findings

On February 4, 1997, the inspector attended the pre-briefing for the planned dive into the No. 1 dilution pump bay. The briefing was conducted using procedure 1000-ADM-1101.01, "Underwater Diving Safety." The inspector noted that the briefing discussed who was in charge of the activity and safety practices that must be followed. The licensee also discussed areas to be inspected using a diagram of the pump assembly. The diver was informed of different possible causes for the rumbling vibration, including foreign material in the pump.

During the dive, a small camera was used to allow real time video inspection by engineering personnel. Industrial safety personnel were also present at the dive site. The cause of the rumbling vibration was identified as the pump impeller rubbing on the pump casing. What caused or allowed the lateral movement of the impeller is unknown at this time. The pump is scheduled to be worked the week of March 24, 1997. Following pump removal and disassembly, a root cause will be determined. The licensee also intends to install some vibration monitoring sensors on the No. 1 dilution pump when it is repaired to allow monitoring and trending during operation. The licensee is also evaluating the placement of vibration monitors on the other two pumps while they are installed.

c. Conclusions

The inspector determined that the licensee had approached this task with a high level of safety. The installation of vibration monitoring sensors on the No. 1 pump was a positive first step to more actively monitor the performance of all the dilution pumps.

M1.5 "E" Recirculation Pump Motor Generator Set Cable Replacement

a. Inspection Scope (37551, 62707)

The inspector followed the licensee's 4160 volt cable replacement activities for the "E" recirculation pump motor generator (RPMG).

b. Observations and Findings

On February 11, 1997, at 8:06 p.m., the "E" RPMG 4160 volt motor supply cable failed. The plant responded normally to the loss of one recirculation pump. Subsequent investigation by the licensee indicated the "flag" on the ground sensing relay had picked up. Subsequent investigation by electrical maintenance personnel identified a short of the "B" phase to ground. During the period of February 12 through 21, 1997, the licensee replaced the cables for the "E" RPMG set. The recirculation pump was restarted and placed in service on February 21, 1997, at 12:10 p.m. During the cable replacement activities, the inspector made routine observations of ongoing activities and cable testing. The failed cable was "Anaconda," size 0000, EPR unishield insulation, and had been installed in 1984. The cable was replaced with "Cablec," size 0000, improved EPR insulated cable.

The installation was completed without incident. Personnel followed the directions in the job order. Engineering provided strong oversight and support of the activities including the design and rerouting of a section of conduit. The conduit was rerouted because of a misalignment of the conduit where it passed between the reactor building and the turbine building basement. A second benefit of the conduit rerouting was a reduction in personnel exposure. The old routing passed through the reactor building equipment drain tank (RBEDT) room, a locked high radiation area. The licensee estimated that the re-routing of the conduit saved over one rad of personnel exposure.

The inspector also reviewed the results of the 5000 volt megger tests and the 35 kilovolt high pot test. The 10 kilovolt high pot of the cables and motor after the cables were reconnected was also reviewed by the inspector. New cable insulation resistance at 5000 volts, after 10 minutes, was greater than 100,000 megohms, with both positive and negative polarity. At 35 kilovolts, after 5 minutes, leakage current was 0.5 microamps which equates to a resistance of 70,000 megohms. Leakage current of the cables when connected to the motor was 5 microamps after 5 minutes at 10 kilovolts or 10,000 megohms. These results satisfied the associated acceptance criteria.

c. Conclusion

The inspector determined that the cable replacement was completed without error. Personnel followed applicable instructions and engineering provided strong support to maintenance personnel. Conduit rerouting modifications were effectively implemented.

M7 Quality Assurance in Maintenance Activities

M7.1 Failure of Limitorque Valve Operator

a. Inspection Scope (40500, 62707, 71707)

The inspector reviewed the licensee's actions concerning the failure of two Limitorque valve operators. The failures were recently (January 27, 1997) reported to the NRC by Limitorque Corporation as a counterfeit parts issue. The inspector also supplied licensee information concerning the motor operator failures and the licensee's actions to the Vendor Inspection Section of the NRR's Special Inspection Branch for additional followup.

b. Observations and Findings

On October 8, 1996, the licensee issued deviation report (DR) 96-870 to document the failure of a Limitorque motor operator for valve V-3-29. A similar failure had previously occurred on V-3-13. These valves are 72 inch valves in the non-safety related circulating water system. The motor operators were SMB-1 size.

The failures occurred after the valves were operated in manual and would not return to the motor operation mode. The licensee determined that the worm shaft clutch gear tripper pin had fallen out preventing the operator from returning to motor operation. The licensee also noted that the operators were not supplied by Limitorque but had been refurbished by a different contractor for use in non-safety related applications.

The failed components (worm shaft clutch gear and tripper pin) were sent to Limitorque for analysis and failure determination. On October 11, 1996, Limitorque informed the licensee that the components were not manufactured by Limitorque and had dimensional and material deficiencies. The licensee informed other licensees of this issue through a "nuclear network" report on October 15, 1996, following the Limitorque notification. On January 27, 1997, Limitorque made an informational report to the NRC of the existence of a "counterfeit" critical component in these non-safety related valves. Following Limitorque's report to the NRC, multiple inquiries from other NRC groups were received at the resident office concerning the failures and the possible wider industry wide implications.

Following the second valve failure at Oyster Creek, the licensee issued a second DR and performed a broad based evaluation of records of all motor operators that were obtained from the subject vendor. There were three additional motor operators of the specific size (SMB-1) with the specific gear size that had failed. All were installed in the circulating water system and all three have had the gear and pin replaced with Limitorque parts. There were a total of 15 motor operators installed in the plant that were not obtained from Limitorque, all in non-safety related systems and all had been satisfactorily MOVATS tested during the Fall 1996 16R outage. The licensee noted that performance during MOVATS testing did not preclude a future failure but indicated satisfactory performance when tested. The inspector questioned the licensee concerning any Limitorque operators that might be in the warehouse. The licensee stated that all valve operators in question had been installed and tested.

Limitorque also mentioned that they used a proprietary process to expand the pin that had come out in the failed motor operator for the two valves. This indicates that the process of installing the pin and worm shaft clutch gear was likely very significant in the failure of the motor operator, as well as the "counterfeit" parts.

c. Conclusions

The inspector concluded that the licensee had properly addressed the two failures of Limitorque motor operators used in non-safety related applications. The licensee promptly verified that the facility had not used any of the non-Limitorque supplied operators in any safety application.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Licensee Event Report (LER) 96-13: Motor Control Center (MCC) DC-2 did not meet seismic design bases. The licensee identified that prior work performed by contractor maintenance personnel during the 16R refueling outage failed to re-install the MCC DC-2 mounting bolts, rendering the safety related MCC inoperable. This occurrence was discussed in detail in NRC Inspection 50-219/96-11 (Section M8.2). This LER is closed.

III. ENGINEERING (37551, 40500, 71707, 92903)

E1 Conduct of Engineering

E1.1 As-Found Field Change Notice (FCN) Technical Review and Approval Deficiencies

a. Inspection Scope (37551, 71707)

On February 18, 1997, the licensee identified that a significant number of Field Change Notices (FCN) have resulted in drawing changes, but did not receive the necessary technical review/evaluation. The inspector reviewed the associated deviation report, interviewed engineering personnel, reviewed the controlling administrative procedure for the FCN process, and reviewed a sample of unreviewed FCNs to determine the significance of this issue.

b. Observations and Findings

The deviation report documented that approximately 940 FCNs resulted in procedure changes without receiving technical reviews. At the time the deviation report was submitted, a review of all FCNs (about 20,000 for Oyster Creek) was continuing to determine the full magnitude of the problem. By the end of the inspection, the total number of affected FCNs was about 970.

The licensee believed that the large backlog of technical reviews of these FCNs was due to individual engineers placing a relatively low priority on them due to an apparent low safety significance (based on an FCN initial screening). The licensee identified this backlog while assessing turnover work loads for corporate engineers following the recent Engineering Department reorganization (Summer - Fall, 1996). The majority of the backlog of FCNs dated from 1985 to 1993. In 1993, when system engineering organization was instituted, the site system engineers became responsible for the reviews, and the backlog was better managed.

The licensee conducted a broad assessment of the FCN backlog and determined that these were "As-found" FCNs, meaning that the FCNs requested a drawing or technical manual change to reflect the as-built condition of the plant. The licensee determined that these are typically administrative in nature and do not affect the design or function of components or systems as described in the UFSAR. Consequently, the licensee concluded the safety significance of not having complete technical reviews of these As-found FCNs did not impact operability.

Notwithstanding the low safety significance, the licensee recognized that the large number of open As-found FCNs represented a concern. Accordingly, they have initiated an effort to complete the required technical reviews for all of the nearly 1000 open FCNs. A list of these FCNs has been developed, and a project manager has been assigned to coordinate the licensee's efforts.

The inspector independently reviewed 95 FCNs selected from the licensee's list. The majority of them were administrative in nature. Sixteen of them were identified to the licensee as potentially having higher safety impact either due to the lack of detailed information in the document or because the FCN involved a nuclear safety-related system. The licensee promptly reviewed those 16 FCNs and determined 1) what the change was, 2) the safety significance, and 3) whether a safety evaluation was required for close-out of the FCN. Their review concluded that none of them were of safety significance and none required a safety evaluation. Six of them were closed out during the review, and the remaining 10 required additional detailed review to complete close-out. The inspector reviewed the licensee's response and found it to be acceptable.

Station Procedure EMP-015, "Engineering Change Documents," requires that Engineering Change Documents (ECD, formerly FCNs) receive a technical review and technical approval. Although the procedure does not identify a required time frame by which the review and approval must be done, an excessive number of As-found FCNs were not technically reviewed and approved in a timely fashion. This licensee-identified violation of station procedure EMP-015 was of low safety significance and will be corrected within a reasonable time; and is therefore being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

The excessive number of As-found FCNs that had not received technical review and approval indicated weak management of the engineering change document process and is a non-cited violation. The licensee's followup actions to their self-identification that a significant number of FCNs did not receive the appropriate technical review and approval were acceptable.

E1.2 Followup and Evaluation for Safety-Related Relay Failures Due to Manufacturing Defect **(Unresolved Item 97-01-02)**

a. Inspection Scope (37551, 40500, 71707)

NRC Inspection Reports 50-219/95-06 and 50-219/95-14 discussed inservice failures and associated licensee followup of General Electric (GE) CR120AD, 120 Vdc relays that were purchased from a vendor, Farwell & Hendricks, Inc. (F&H). The licensee subsequently identified a similar but related problem (same defect) on the same relays purchased directly from GE. The inspector reviewed the associated deviation report (DR) the discussed the status of ongoing testing and evaluation activities with onsite engineering personnel.

b. Observations and Findings

Following Oyster Creek's 15R refueling outage (Fall 1994), three GE CR120AD, 120 Vdc relays failed within three months of completing the outage activities. Nineteen relays were replaced during that outage. GPUN, Inc. purchased the 19 relays as safety related components from F&H, who in turn, purchased them commercially from GE and then dedicated them as safety related relays. The F&H dedication plan for the relays had been approved by a GPUN, Inc. representative.

Independent failure analysis for the relays identified a manufacturing defect as the cause for the failures. Specifically, the start-end of the coil was off the insulating lead pad and was in contact with the outer layer of the coil winding (near the finish-end of the coil). The affected length of coil wire and insulation was placed in a high electrical stress condition that led to dielectric breakdown at the failure site, thus effectively short circuiting the coil. The resulting high current through the short circuit caused the coil wire to fuse and produce an energetic arc at the failure site. Following the three failures and failure analysis results, the licensee 1) placed the vulnerable relays on "QA-hold," to prevent installation, 2) notified F&H of the failure analysis results for 10 CFR Part 21 reportability applicability review, and, 3) notified the nuclear industry of their experiences with these relays via the Nuclear Network. Additionally, F&H subsequently developed a specific bench test which would identify the presence of the defect.

On February 4, 1997, the licensee submitted a deviation report identifying problems with four GE CR120AD, 120 Vdc relays that were purchased in 1994 directly from GE as safety related components. Specifically, one of those relays was found with essentially an identical failure site and mechanism as the other relays purchased from F&H. In the Summer of 1996, GPUN, Inc. had sent that GE-supplied safety related relay (the other three were installed in the plant) to F&H for bench testing to determine whether the defect was present as part of their enhanced testing program. The associated August 1996 report from F&H identified the same failure site for that GE-supplied relay. Subsequently, that same relay, as well as an additional in-stock relay that had previously passed the F&H special test, were sent to another independent vendor for destructive physical analysis to confirm the August 1996 findings. The completed analysis report, dated January 7, 1997, confirmed the same type and location of failure for the GE-supplied relay, while no failure site was identified on the "good" F&H dedicated and tested relay.

Following the initial identification of this issue after 15R, the licensee addressed operability concerns for the installed relays. That included assessing the function and failure mode for each of the installed relays, including indications of a failure to the control room operators. They also reviewed the inservice test history for each of the relays, and determined that sufficient testing or cycling was performed to provide assurance that the relays were operable. As an additional conservative action, the licensee replaced 17 of the installed relays during the recent 16R refueling outage with those from in-stock storage. However, due to an apparent communication weakness, only 10 of the 17 had been tested by the F&H special test procedure. As a result, the licensee performed a similar operability assessment to that which was done previously for the 17 relays. The associated Conditional Release listed the function of each of the 17 relays, the normal state (all are normally energized), and the impact of a relay failure. In addition, the licensee noted that based on current knowledge and experience, the failure mode of the specific manufacturing defect typically results in a pre-mature failure (immediate to three months). The relays had all operated in excess of five months.

At the end of this inspection, there were two issues related to 10 CFR Part 21 reporting. The licensee informed the inspector that F&H had previously indicated to them (GPUN Inc.) that F&H submitted a 10 CFR Part 21 report for the relays that they dedicated and provided to Oyster Creek as safety related. However, it was not apparent that the associated report was ever completed and submitted to the NRC.

The second issue is more recent and is related to the relays supplied directly by GE as safety related components. There appears to be a conflict in determining that the failed relay in question is in fact the GE-supplied relay. This must be resolved in order to determine proper reporting and characterization, and is important in determining the generic nature of this issue. Pending resolution of these two issues, this is an unresolved item. **(URI 50-219/97-01-02)**

c. Conclusions

The inspector concluded that the licensee had provided appropriate attention to the outstanding issue of whether relays for safety related applications are properly tested and monitored. The licensee's conditional release was acceptable, although it became necessary only due to a communication weakness. Continued aggressive followup on this issue is warranted to achieve full resolution.

E2 Engineering Support of Facilities and Equipment

E2.1 "C" Recirculation Pump Motor Generator (RPMG) Set Trip

a. Inspection Scope (37551, 71707)

The inspector reviewed the safety determination and procedure change that allowed an increase of the high current limit of the RPMG set motors and subsequently resulted in a trip of the "C" RPMG.

b. Observations and Findings

Following the failure of the "E" RPMG set cable (see section M1.5 of this report), the licensee continued operation with four of the five recirculation loops in operation. With only four loops in operation, the plant could not attain full power because the "C" RPMG set motor current reached its administratively controlled high limit of 210 amps. The limit was reached when recirculation pump speed was increased to raise plant power following the "E" recirculation pump trip. The "C" RPMG motor current runs slightly higher than the other RPMG sets. Maximum power at the time was about 97 percent. Since the plant was expected to be in the four loop configuration for an estimated 10 to 12 days, operations management requested engineering to evaluate and recommend a means to increase reactor power to 100 percent.

Engineering evaluated the options possible and decided to increase the motor current limit to 235 amps. A safety determination was performed by engineering and a procedure change was implemented. A crew briefing was conducted prior to increasing the speed of the recirculation pumps. The system engineer was also present in the control room monitoring the RPMG set motor amp indicators. When control room operators increased pump speed, the "C" RPMG set voltage and current became unstable at about 220 to 225 amps and the RPMG set tripped on loss of field in about 2 seconds. The trip occurred at 6:35 p.m. on February 12, 1997. The loss of the second recirculation pump resulted in a power decrease to about 94 percent and placed the licensee in a Technical Specification (TS) 12 hour required shutdown. A shutdown was promptly initiated by control room operators. Electrical maintenance personnel checked the "C" RPMG and its voltage regulator. No problems were identified, and the "C" recirculation pump was restarted and placed in service at 9:45 p.m., and the 12 hour shutdown was terminated. Power had been reduced to 74 percent before exiting the applicable TS. The plant power was increased, and reached 98 percent at 2:20 a.m. on February 13, 1997. Power was restricted at the previous 210 amp limit on the "C" RPMG motor.

The inspector questioned the licensee to determine if non-conservative or inappropriate decisions had led to the "C" RPMG set trip. The inspector determined that the increase in RPMG set motor current was within the nameplate rating of 239 amps. The ability of the voltage regulator to control voltage at the higher current levels was also questioned. The licensee noted that the voltage regulator had been completely refurbished during the last outage with numerous components replaced. The voltage regulators had been very stable during the current operating cycle in five loop operation. Some oscillations had occurred during previous cycles. The system engineer observing the motor amps stated that at 210 amps on the "C" RPMG (starting point for this evolution), there was some minor oscillation. The voltage regulators during the previous operating cycles had generally displayed instability that increased with load such that load increase could be stopped before an RPMG set tripped. Based on current cycle indication and the recent refurbishment the engineering staff thought that the regulators would be capable of regulating voltage at the higher motor current levels.

The discussions did identify, that due to system design and recirculation pump restrictions, the licensee does not have the ability to align the voltage regulators in accordance with the voltage regulator technical manual. The technical manual alignment procedure discusses load application and rejection and adjustment from zero to full load. These adjustments cannot physically be accomplished. Load application and rejection is not possible without stopping and starting the pump because the RPMG output to the recirculation pump does not have a breaker in the circuit.

Maximum recirculation pump speed (RPMG load) when cold is restricted to less than 36.5 Hz due to vibration concerns. Speed was not restricted prior to 16R; however, the root cause of a recirculation pump bearing failure when coming out of the last refueling outage was determined to be vibration due to high pump speeds while cold. There are also restrictions on pump speed balance between loops when hot due to flow induced vibrations. The inspector asked how the regulators were aligned with all the pump restrictions. The system engineer stated that the regulators were set to the original settings after refurbishment and checked at 35

Hz when first started to ensure voltage and current were within specifications. Observations during startup up to full power with five loops in operation were quite stable, with voltage and currents at the expected values.

Licensee management noted that further evaluation concerning possible methods to adjust the regulators at the high end of the current output were being evaluated as well as possible modifications to further stabilize the voltage regulator. In the interim the licensee has restricted RPMG generator output current to 210 amps during four loop operation.

Additional licensee investigation into the background information concerning this event identified a trip of the "D" RPMG set on February 12, 1995, due to voltage regulator instability during four loop operation. A Deviation Report (95-074) was issued, with refurbishment of the voltage regulators as a long term corrective action. Refurbishment was accomplished during the 16R outage.

c. Conclusions

The inspector concluded that although a procedure to effectively adjust the RPMG sets voltage regulator was not available (such a procedure may not be possible due to recirculation pump operating restrictions and system design), the licensee had made reasonable effort to return regulator adjustments of this important to safety equipment to the original settings and verified proper regulator response during power ascension. Based on knowledge of regulator refurbishment and observations of stable voltage regulator response since restart from 16R, the licensee had taken reasonable steps to consider increasing the motor current limit in order to increase reactor power. However, because 1) the licensee observed a minor oscillation at 210 amps during the increase (prior to the trip at about 225 amps), 2) it is recognized that an effective voltage regulator adjustment was not possible, particularly at higher RPMG set speeds, 3) there have been prior and repeated RPMG set operational problems, and 4) the RPMG sets play an important role in reactivity management, the inspector concluded that the licensee's decision to proceed did not reflect a conservative approach.

E2.2 Isolation Condenser Vent Radiation Monitors Removed From Service Prior to Addressing All Relevant UFSAR Commitments **(Unresolved Item 97-01-03)**

a. Inspection Scope (37551, 40500, 71707)

On February 6, 1997, the licensee submitted a Deviation Report (DR) after they identified that the isolation condenser vent radiation monitors were previously removed from service via a plant modification without identifying that the radiation monitors fulfilled a NUREG 0737 (Three Mile Island Action Plan) commitment. The inspector reviewed the DR, the safety evaluation that was used to support the modification, applicable sections of the UFSAR, NUREG 0737, and meeting minutes of a February 7, 1997, Plant Review Group (PRG) meeting. In addition, the inspector discussed the details and the implications of not meeting the associated NUREG 0737 commitments with both licensee and NRC personnel.

b. Observations and Findings

In December 1995, the licensee removed from service the isolation condenser (IC) vent radiation monitors. A safety evaluation was completed at the time to support the modification. Although the safety evaluation recognized and noted that UFSAR Section 11.5.2.3, "Containment Spray Heat Exchanger/Service Water Area Monitors and IC Vents Monitors," needed to be addressed, other UFSAR sections were missed. The most significant section that was missed was 1.9.31, "Item II.K.3.14 - Isolation of ICs on High Radiation." That section documents the NRC Position on the issue and the GPUN Response. The UFSAR section documents that the NRC staff has concluded that the IC manual trip on high radiation levels at the vents is sufficient to provide the amount of flexibility and system availability intended by this item.

The function of the IC vent radiation detectors was to provide a leak detection indication to the control room operators so that they could manually isolate the affected IC upon a tube leak from the reactor coolant system, thereby preventing a release of radioactivity to the environment. However, the licensee stated that the operational characteristics of the system represented a potential source of operator confusion since background radiation in the vicinity of the radiation monitors with the ICs in service masked their capability for leak detection (i.e. due to expected radiation level increase for normal IC system operation without a tube leak).

The intent of NUREG 0737, Item II.K.3.14, was to have licensees change the source for the IC automatic isolation signal due to high radiation from the steam lines (that lead to the ICs) to the IC vents. That is, the design was to be modified such that the ICs were automatically isolated upon receipt of a high radiation signal from the IC vents rather than at the steam line for the purpose of increasing IC availability as heat sinks (preventing spurious isolations). In an April 30, 1981, letter to the NRC, GPUN stated that Oyster Creek uses excessive flow in the steam lines to and condensate lines from the ICs as the only isolation signal for the system isolation valves. GPUN further stated that because the Oyster Creek IC system is different from the one described in the NUREG, no additional modifications were required. The NRC's response letter, dated December 18, 1981, stated that GPUN's April 30, 1981, response was acceptable and the item was considered resolved.

The current licensee's position is that the intent of NUREG 0737, Item K.II.3.14 is met by the excessive flow sensors alone. They further believe that if the vent radiation monitors were continued to be used at Oyster Creek to initiate a manual isolation, the situation that the NUREG Item was attempting to avoid (unwanted and unnecessary isolations) would be created. The licensee also stated that Oyster Creek currently relies on a combination of procedurally directed on-site monitoring and the use of other control room indications/alarms to alert the operators to the need to manually isolate one or both of the ICs.

The inspector's review of the NRC December 18, 1981, safety evaluation report (SER) confirmed that the SER was generic in nature in that seven nuclear plants, including Oyster Creek, were addressed. However, the SER recognizes that all the plants have radiation monitors and alarms at the IC vents, and that six of the seven (including Oyster Creek) require manual isolation of the IC if considered necessary by the operators.

The licensee's PRG met on February 7, 1997, to consider reportability of the issue described in the February 6, 1997, DR. The PRG concluded that the Oyster Creek commitment relative to NUREG 0737, Item II.K.3.14 was contained in their April 30, 1981, letter, in which no reference was made to manually isolate the ICs upon receipt of a vent radiation monitor alarm. The NRC's December 18, 1981, SER granted approval based upon the licensee's April 30, 1981, letter. Therefore, the PRG determined that Oyster Creek has not violated its Item II.K.3.14 commitment (although it appeared to be incorrectly stated in the UFSAR Section 1.9.31). In addition, the PRG concluded that Oyster Creek procedures currently would lead to manual IC isolation in the event of a tube leak based upon using a combination of on-site radioactivity monitoring and control room indications/alarms, such as steam line temperatures and shell levels and temperatures.

c. Conclusions

The significance of removing the problematic IC radiation monitors appeared to be relatively low because of the distraction they provided to operators upon IC system initiation. However, the inspector concluded that the August 1995 safety evaluation, performed to support the December 1995 modification, was incomplete in that it did not recognize that the IC vent radiation monitors appeared to be a NUREG 0737 requirement. This is another dated example of failure to conduct an adequate UFSAR review for which the licensee is currently addressing programmatically for future safety evaluations. This additional example indicates the need to perform reviews of other previously completed safety evaluations to determine whether other commitments or UFSAR items had been overlooked.

The inspector concluded that additional information is necessary to determine whether the licensee is in conformance with NUREG Item II.K.3.14. Specifically, the basis document that provided the existing UFSAR Section 1.9.31 commitment description must be identified and reviewed. The inspector informed the licensee of the additional information and review needed for this issue. Pending completion of the above by the licensee and followup by the NRC, this is an unresolved item. **(URI 50-219/97-01-03)**

E2.3 Update of Mercoid Temperature and Pressure Switch Failures

a. Inspection Scope (37551)

The inspector reviewed the initial results of an independent laboratory analysis of failures of recently installed Mercoid temperature switches in the stator cooling system. The switches are Mercoid Model DA-35-804-6. Recent events concerning these switches are also discussed in NRC Inspection Report 50-219/96-11.

b. Observations and Findings

On January 2, 1997, the licensee initiated deviation report (DR) No. 97-063 and material nonconformance report (MNCR) No. 97-003 when initial reports from an independent laboratory identified several deficient conditions associated with the Mercoid switches the laboratory had analyzed. These switches were determined to be the cause of the turbine runback and manual reactor trip on October 25, 1996. The licensee's maintenance department (I&C) determined that the thermobulb capillary tubes were sensitive to temperature changes which could activate the switches (NRC Report 50-219/96-11). The defective switches were replaced with a temperature switch supplied by a different vendor (Ashcroft). The defective switches were sent to an independent laboratory for analysis to determine root cause for the failures. In addition to the licensee's identification of temperature sensitivity, the laboratory identified two other defects in the switches. The first was a failure (crack) of the actuator arm (from bourdon tube to mercury switch) trip setpoint adjustment screw varnish or epoxy locking medium, which was put on the screws to prevent loosening. Failure of the locking medium could allow the setpoint adjustment screws to loosen and change the actuation setpoint of the switch. The linkage on the old switches were more substantial and the adjustment screws did not use varnish or epoxy to prevent loosening. A mechanical locking tab was previously used. The second problem identified was a loss of fill medium (thermobulb and capillary tubing) due to poor brazing or soldering during manufacture which could also cause erratic instrument switch operation.

Following notification by the laboratory, the licensee issued the DR and MNCR to address the defective switches. The preliminary report also identified that not only were temperature switches affected, pressure switches of similar design were likewise affected. As a result the licensee conducted a search of the computerized component system (GMS2) for all Mercoid switches. Seventy-three switches were identified. None of the switches identified were used in safety related applications and the inspector did not identify any other applications of safety concern. The licensee performed a walkdown of all identified switches and identified six that were of the type in question and initiated action to have all six switches replaced. The six identified were: one in the "B" control rod drive pump low suction pressure trip, three in the stator cooling low pressure runback circuit (currently monitored by additional installed instrumentation), one in the "A" main feedpump bearing lube oil low pressure trip, and one in the emergency start circuit of the main turbine seal oil pump. These switches will be replaced in the near future. The main feed pump must be secured to replace the low bearing lube oil pressure switch because the switch cannot be isolated. The feed pump switch replacement will be performed in conjunction with a scheduled quarterly power reduction for main steam isolation valve full closure surveillance testing. System engineering also recommended that subsequent issue of these switches be terminated and that spare switches be removed from the spare parts inventory.

Due to the several deficiencies identified with the Mercoid switches, there appears to be several contributing causes of the main turbine runback with the subsequent manual reactor scram by control room operators. To date, only preliminary reports have been received from the independent laboratory. When the final report is received, the licensee will make a Nuclear Network announcement to inform other licensees of the Mercoid switch problems.

c. Conclusions

The inspector concluded that the licensee had demonstrated perseverance in their pursuit of a root cause. They did not cease activities when switches demonstrated a sensitivity to temperature changes, but rather sent the defective switches to an independent laboratory for further analysis. The licensee also took prompt and effective action to identify other switches in the plant that were of the same type and have initiated action to replace them.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item 50-219/95-24-01: This item concerned licensee actions during maintenance to stator cooling multi-channel recorder. Similar issues were subsequently identified and tracked in NRC Inspections 50-219/96-07 and 96-09. The licensee has responded to the broader concern as presented in those reports. In addition, specific procedural changes were implemented for station procedure 108.8, "Temporary Modification Control," to address related concerns. The inspector reviewed the licensee's actions in response to this item. Other related details are currently being tracked separately, in NRC open item 50-219/96-09-04. This item is closed.

E8.2 (Closed) Licensee Event Report (96-12): Racked out breakers in 4160 Vac switchgear did not meet seismic design bases. The licensee implemented effective immediate actions to address operational concerns associated with the affected 4160 Vac breakers, and conducted a similar review for 480 Vac breakers. This issue was previously discussed in detail in NRC Inspection 50-219/96-12 (Section 02.1). This LER is closed.

E8.3 (Closed) Licensee Event Report (96-14): All four steamline low pressure sensors found below technical specification limits. NRC Inspection Report 50-219/96-12 (Section M1.4) discussed this event in detail. This LER is closed.

E8.4 (Closed) Licensee Event Report (96-15): Reactor water cleanup system valves may not operate during a line break due to a non-conservative analysis. The licensee implemented prompt and appropriate short term actions. This issue was discussed in NRC Inspection 50-219/96-12 (Section E1.1) This LER is closed.

E8.5 (Closed) Licensee Event Report (97-01): Seven drywell penetrations do not meet the requirements described in NRC Generic Letter 96-06. This issue was discussed in NRC Inspection 50-219/96-12 (Section E1.2). This LER is closed.

IV. PLANT SUPPORT (71707, 71750, 93702)

R1 Radiological Protection and Chemistry Controls

R1.1 General Observations

During entry to and exit from the radiologically controlled area (RCA), the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. During periodic plant tours, the inspectors verified that posted extended Radiation Work Permits (RWP) and survey status boards were current and accurate. They 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.

R1.2 Automatic Trip of the Augmented Offgas System/Building and Radioactive Airborne Contamination Due to Subsequent Equipment Failure

a. Inspection Scope (71707, 71750, 93702)

On February 6, 1997, the augmented offgas (AOG) system isolated due to a momentary loss of power that occurred after an automobile hit a local utility pole. Subsequently, an equipment failure resulted in radioactive airborne contamination in the AOG building. The inspector responded to the control room following the event, interviewed operations and radiological controls (radcon) personnel, reviewed system drawings, and monitored the licensee's followup activities.

b. Observations and Findings

The AOG system functioned as per design when it tripped and isolated following the momentary power loss. Operators immediately responded to the AOG building and found that conditions in the building appeared normal. The backup power supply was available, which automatically transferred, and operators were preparing to place AOG back in service. However, while the operators were reviewing the associated procedure, they heard a "pop" from the "B" hydrogen detector followed by a rush of air leakage. They also noted an increase in building radiation levels. The operators immediately evacuated the AOG building due to the elevated radiation levels and not being able to isolate the leak.

Within 30 minutes of the loss of power, operators re-entered the building with radiological controls personnel and instrument maintenance technicians. The maintenance technician opened a recombiner hydrogen detector panel and re-connected a section of tubing that had apparently blown off its connection within the panel.

When the AOG system isolates, an air purge valve automatically opens to purge the contents remaining in the recombiner. An associated system vent valve opens to provide a release pathway (to the stack) of the purged volume. Both the air purge and system vent valves are subsequently closed by individual time delay relays (after about 15 minutes). In this case, the relay associated with the air purge valve failed, resulting in the air valve remaining open and providing air to the recombiner at about 30 psig. Normal operating pressure for the recombiners is 2 psig. The increased air pressure caused the hydrogen detector's tygon tube to blow off. As a result, the unprocessed noble gas volume remaining in the recombiner after the isolation (combined with the purge air) was released into the AOG building.

Radiation protection personnel responded to the event to assess radiological conditions both inside and outside the building. The radiological implications were small. The majority of the activity remained in the building, and was removed via the AOG building ventilation system, which utilizes a HEPA filtering system. The licensee postulated that a very small amount of activity may have exited the building through exfiltration (through building crevices) during the short time that the ventilation system was not operating (immediately after the loss of power).

Air samples obtained by radiological controls personnel outside of the building immediately following the event showed no activity. Particulate air samples inside the building showed 0.1 Derived Air Concentration (DAC). No iodine was detected inside or outside of the building. The licensee's total release calculation (estimate) yielded 42 mCi total noble gas.

In responding to the event, two individuals received skin contamination (hands) from the airborne noble gas. Both were decontaminated by decay after a short time period.

The licensee subsequently identified the failed relay and replaced it. The tubing was secured to the hydrogen analyzer, and the AOG system was returned to service.

c. Conclusions

The inspector concluded that this was not a significant event from a radiological perspective. Radiological controls personnel responded quickly and appropriately to the occurrence. Operations and maintenance personnel likewise responded quickly and effectively to this event.

S1 Conduct of Security and Safeguards Activities

S1.1 General Observations

During routine tours, access controls were verified in accordance with the Security Plan, security posts were properly manned, protected area gates were locked or guarded, and isolation zones were free of obstructions. Vital area access points were examined and verified that they were properly locked or guarded, and that access control was in accordance with the Security Plan.

V. MANAGEMENT MEETINGS (71707)

X1 Exit Meeting Summary

A verbal summary of preliminary findings was provided to the senior licensee management on March 17, 1997. 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.

X2 NRC Region I SALP Management Meeting and Plant Tour

On January 27, 1997, the NRC Region I Deputy Regional Administrator and the Region I Director, Division of Reactor Projects, toured the Oyster Creek facility, interviewed several licensee personnel, and convened a public meeting to present the NRC's Systematic Assessment of Licensee Performance (SALP) to senior GPUN, Inc. management. The assessment was presented by NRC personnel, with open discussions between the NRC and the licensee concerning SALP topics.

ATTACHMENT 1
PARTIAL LIST OF PERSONS CONTACTED

Licensee (in alphabetical crder)

G. Busch, Manager, Regulatory Affairs
B. DeMerchant, Licensing Engineer, Regulatory Affairs
S. Levin, Director, Operations and Maintenance
K. Mulligan, Manager, Plant Operations
M. Roche, Director, Oyster Creek

NRC (in alphabetical order)

L. Briggs, Senior Resident Inspector, RI
R. Cooper, Director, Division of Reactor Projects (DRP), RI
P. Eselgroth, Branch Chief, DRP, RI
W. Kane, Deputy Region I (RI) Administrator
S. Pindale, Resident Inspector, RI

ATTACHMENT 2
INSPECTION PROCEDURES USED

Procedure No.	Title
40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
37551	Onsite Engineering
61726	Surveillance Observation
62707	Maintenance Observation
71707	Plant Operations
71750	Plant Support
92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
92901	Followup - Operations
92902	Followup - Maintenance
92903	Followup - Engineering
92904	Followup - Plant Support
93702	Onsite Event Response

ATTACHMENT 3
ITEMS OPENED AND CLOSED

Opened

Number	Type	Description
97-01-01	VIO	Failure of the procedure to establish controls that the tagging order for a hydraulic control unit was satisfactorily accomplished (01.2).
97-01-02	URI	Resolution of issues related to 10 CFR Part 21 reportability responsibility for defective General Electric CR120AD relays - two separate vendors and utility involved in review. (E1.2)
97-01-03	URI	Isolation condenser radiation monitors removed from service via a plant modification without fully addressing continued conformance with applicable UFSAR commitments and NRC requirements. (E2.2)

Closed

Number	Type	Description
95-24-01	URI	Licensee actions following a defeated stator cooling system multi-channel recorder. (E8.1)
96-12	LER	Racked out breakers in 4160 Vac switchgear did not meet seismic design bases. (E8.2)
96-13	LER	Motor control center DC-2 did not meet seismic design bases. (M8.1)
96-14	LER	All four main steamline low pressure sensors found below technical specification limits. (E8.3)
96-15	LER	Reactor water cleanup system valves may not operate during a line break due to a non-conservative analysis. (E8.4)
97-01	LER	Seven drywell penetrations do not meet the requirements described in NRC Generic Letter 96-06. (E8.5)