U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-219/88-38

Docket No. 50-219

License No. DPR-16 Priority -- Category C

Licensee: GPU Nuclear Corporation
1 Upper Pond Road
Parsippany, New Jersey 07054

Facility Name: Oyster Creek Nuclear Generating Station

Inspection Conducted: December 4, 1988 - January 14, 1989

Participating Inspectors: W. Baunack
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Approved By: C Cowgill III 2/21/89
C. Cowgill, Chief, Reactor Projects Section 1A Date

Inspection Summary:

Areas Inspected: Routine inspections were conducted by the resident and one region-based inspector (294 hours) of activities in progress during the outage, including maintenance and surveillance activities, radiation control, and physical security. In addition, inspectors reviewed two security events involving a potential unauthorized entry in a vital barrier and loss of security electrical loads, control room loose wires, scram discharge volume foreign material and cleanliness flushing practices, air accumulator testing, torus tiedown bolt material condition, CRD return line piping wall thickness, and refueling operations. The inspectors also conducted a review of the preliminary safety concern process and several particular safety concerns. Initial review of the operability status of the source range monitors prior to refueling was also conducted. An LER review was conducted to assess any identifiable trends or weaknesses.

Results: The inspectors identified five unresolved items. The unresolved items included concerns regarding the single failure susceptibility of the standby gas treatment system automatic initiation logics, vital area unauthorized entry, deletion of SDV flushing requirements and programmatic implementation of cleanliness standards for piping system, completeness of testing of air accumulators associated with safety related valves, and the quality control process used to verify the adequacy of shop spare parts prior to installation. The inspectors developed concerns regarding the proper and timely processing of preliminary safety concerns identified by employees. Valid safety concerns actually remain open when the tracking system indicates their completed disposition. An error-free refueling of the reactor was completed during the period.

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DETAILS

1.0 Drywell Entry

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This item will remain an unresolved item pending further inspector review (50-219/88-38-01).

2.0 Control Room Loose Wires

During the report period the licensee discovered loose wires behind control room panels 5F, 6F, and 11R and in panel ER-18 in the 480 volt room. The inspector discussed with the licensee their plans to verify electrical terminations prior to plant restart as a result of the extensive maintenance activity conducted in safety related control panels. The licensee elected to perform an engineering evaluation to assess the proper method to verify control panel electrical terminations. Inspection Report 50-219/87-04 discusses similar loose connections discovered by the licensee and corrective action taken to resolve the loose wires.

The loose wires found in the control room are normally terminated in a compression terminal strip. The wires are not lugged and landed, but simply placed under a spring steel clip with compression force supplied by a set screw. In some cases, two different gauge wires are placed under the same compression clip which, with vibration or force exerted on the wire wrap bundle may loosen or pull the wire free from the terminal strip and break the electrical connection. The different gauge wire may promote loose terminations by allowing the smaller gauge wire to pull free as the larger gauge wire absorbs the compression clip force. After the previous loose wires event, the licensee implemented controls and performed extensive inspections to ensure loose wires would not be a problem during plant operation.

The loose wire in panel ER-18 resulted from an HFA relay replacement in the panel when the electrical lead was not relanded following the relay replacement.

After discovering the loose electrical connection in panel 11R the licensee elected to reland the wire in the compression terminal strip. Prior to accomplishing this task the licensee performed an engineering evaluation to determine what the plant response would be to relanding the loose wire. When making the determination the plant response was not as expected. In reviewing this event the licensee determined that the unexpected plant response resulted from personnel error of the plant engineers who reviewed the electrical termination drawings. The inspector examined microfiche electrical termination drawings for panel 11R and found the prints to be of poor quality and difficult to read and were marked "best available". The inspector will review the licensee critique on this event and plans for inspection of electrical terminations prior to plant restart.

3.0 IRM Spiking Problems

During this report period the facility experienced a number of IRM spikes. On 12/31/88 and again on 1/2/89 full scram signals occurred with the plant in a cold shutdown condition. The licensee could not detect any maintenance or surveillance activities that could have caused the IRM spikes to produce a full scram. On 1/6/89 the inspectors observed numerous half scrams occurring from IRM 12 spikes. The spiking problems have been observed on IRM's 11, 12, 13, 15, and 17. The IRM instrument problem has historically been a problem without resolution. The licensee plans to perform troubleshooting efforts to ensure the IRM's are functional prior to restart from the outage. The inspector will follow licensee activities.

4.0 Preliminary Safety Concern Review

During this report period, the inspectors visited the corporate office in Parsippany, NJ to review preliminary safety concerns (PSC) and the PSC process. As a result of this review the inspector expressed concern regarding the length of time to address PSC's, in many cases this was greater than one year and involved legitimate safety problems. The licensee committed in a letter (dated 12/3/86) to Region I in response to Inspection Report 50-219/86-24 (dated 11/4/86), to resolve PSC's in a timely fashion. During the inspector's review the new proposed revision to the preliminary safety concerns procedure entitled, "Management of Potential Safety Concerns," 1000-ADM-7330.01 written to incorporate the commitments reflected in the licensee's 12/3/86 letter was examined. The proposed revision did not reflect the licensee's commitment to incorporate time constraints in the processing of PSC's to ensure timely resolution of safety concerns.

The second concern the inspectors expressed involved the closure of PSC's with outstanding action items left unresolved. The licensee has in the past closed PSC's on the basis of issuing other action items to be resolved such as Technical Function Work Requests (TFWR) or licensing action items (LAI), for example. The inspectors discovered two examples of this concern in the limited review they conducted of the PSC's. PSC 84-018, reported 10/10/84, addressed a concern regarding a single failure susceptibility of a power supply disabling the standby gas treatment system (SBGTS) logics and control power (see paragraph 5.0) and that could render the automatic initiation of SBGTS inoperable. (In addition, operation of the system in a manual mode may be limited and warrants further review.) A TFWR was issued on 1/28/85 to resolve this issue and closed in 10/87 based on the evaluation results of the PSC which concluded that although it was a valid single failure susceptibility, it was in accordance with the plant design basis and the SEP (see paragraph 5.4). It appears that no real evaluation of the safety concern was carried out under the TFWR. The TFWR simply relied on the evaluation in the PSC which in turn was closed and the action item turned into an apparently untracked TFWR. Thus, the PSC transmitted the concern to a TFWR which was closed based on the PSC evaluation. In addition, this item took three years to close and may have overlooked a valid safety problem (see paragraph 5.0).

The second example of a safety concern that remained open and untracked with the PSC considered closed was PSC 86-20 (reported 10/14/86). This PSC expresses a safety concern regarding nonfunctioning of the containment spray system automatic initiation logic after a single failure of the 125 VDC power panel. LER 86-23 addresses this concern. The licensee issued TFWR No. A01692 and Topical Report 038 to justify eliminating the automatic initiation of the containment spray system. During this report period the inspector was unable to determine the status of the TFWR, but was later informed by the licensee that elimination of the automatic initiation of containment spray system was being re-evaluated. In addition PSC-87-003 was written to address another concern with containment spray system logics. This concern is developed in Inspection Report 50-219/87-04. The concern involves containment spray system automatic initiation logics in the dynamic test mode. In this mode, coupled with a Lo-Lo reactor water level signal, the drywell may be inadvertently sprayed. Also, another concern involves the dynamic test mode used to facilitate torus pool cooling. In an accident situation, the ability to cool the torus may be prevented until the logics may be overridden (see Inspection Report 50-219/87-04).

The licensee resolved this PSC based on the evaluation performed for PSC 86-20 above. Essentially, this item remains open. The licensee has initiated a method to status open PSC's which is a good initiative and currently carries only three open PSC's. This does not include the PSC's mentioned above, though. The status of PSC's receives wide distribution within the corporation including the GORB, but does not include those PSC's which may have open issues as indicated above.

During this review the inspectors noted that some individuals perceived that PSCs would not be resolved in a timely manner nor were welcomed as a mechanism for resolution of potential safety problems. Further, some individuals who could be expected to submit a PSC were not knowledgeable of the process.

Based on the above review, the inspectors expressed concern that the process is not working as described, in that concerns are sometimes not resolved in a timely manner, and that some PSCs were closed without appropriate reviews being complete. Additionally, some site staff members appear to have lost confidence in the process.

The inspectors plan further review of the PSC process and specific PSC's.

5.0 Standby Gas Treatment System (SGTS) Logic

5.1 Item

As a result of the Preliminary Safety Concern (PSC) review discussed in paragraph 4.0, inspectors identified one PSC initiated in 1984, #84-018, which addressed, in part, the potential inability of the SGTS initiation logic to meet single failure criteria. The specific concern was that upon opening or loss of breaker #20 from Vital AC Panel (VACP)-1, the automatic initiation logic of the SGTS would be disabled.

The PSC evaluation concluded that while the SGTS initiation logic does not strictly meet single failure criteria, this configuration was in accordance with original plant design. It also referred to the Integrated Plant Safety Assessment, Systematic Evaluation Program (SEP) review for Oyster Creek, NUREG-0822, evaluation of the loss of VACP-1. As a result of the PSC evaluation, a Technical Functions Work Request

(TFWR) was initiated to review possible design changes. This was subsequently closed evaluating the changes as not required. No modifications were initiated to address this concern.

5.2 Review

Inspectors reviewed the electrical configuration of VACP-1. This 120 vac panel is supplied from either of two safety related 480 vac unit substations through an automatic transfer switch. Power then goes through a disconnect switch and a 480/120 v transformer to VACP-1. From review of this configuration, it can be seen that there are several single failures which could interrupt power to VACP-1, and thus to the SGTS automatic initiation logic.

Inspectors reviewed the electrical elementary drawing to determine the effects of a loss of VACP-1 (breaker #20) on the SGTS. Since the SGTS initiation relays energize on an automatic initiation signal, and the SGTS logic is energized by VACP-1, the automatic initiation of the SGTS is rendered inoperable without logic control power. The fans could be started manually, but the system would apparently operate in a degraded mode since the preheater automatic temperature control would also not be operating.

In addition, VACP-1 breaker #20 supplies power to the reactor building (RB) damper controls, turbine building (TB) ventilation control, main exhaust dampers, drywell and torus exhaust dampers, drywell vent and purge valves and control room ventilation controls for train "A". The exact extent of the impact of a loss of VACP-1 #20 on these components is still under review.

5.3 Discussion

The SGTS is a plant engineered safety feature (ESF) reactor building atmosphere cleanup system which functions as a barrier between the radiation source and the environs during emergency conditions. Upon initiation and secondary containment isolation, the system establishes a negative pressure in the RB, thus preventing ground level leakage of untreated radioactive material from the RB to the environs; and the system treats the RB atmosphere prior to exhausting via the plant stack. Section 6.5.1.2.1 of the plant updated Final Safety Analysis Report (FSAR) describes the SGTS as consisting of two redundant, full capacity parallel flow trains. Section 6.5.1.2.4 of the FSAR describes the system as automatically starting during the Design Basis Accident (DBA) upon receipt of an initiation signal.

The instrumentation and controls section of the FSAR, 7.3, discusses the instrumentation provided to initiate ESF systems, including the SGTS. This system has both Reactor Protection System (RPS) and Non-RPS initiation signals. Sections 7.2.2.1 and 7.3.5.2 of the FSAR state that both the RPS and Non-RPS systems will automatically perform their protective functions whenever plant conditions exceed preset levels and that no single failure can prevent the initiating circuits from performing their protective functions. In addition, 10 CFR 50 Appendix A, General Design Criteria 41, Containment Atmosphere Cleanup, specifies that each system shall have suitable redundancy to assure that its safety function can be accomplished assuming a single failure.

5.4 Integrated Plant Assessment Systematic Evaluation Program (SEP)

Topic VII-3 of the SEP evaluated the effects of a loss of VACP-1 on the ability to place the plant in a safe shutdown condition. A limited probabilistic risk analysis (PRA), discussed in Appendix D of the SEP, dealt with the contribution to risk of the loss of VACP-1 powered control room indications. The NRC concluded that the increased probability of operator error due to lost indication did not contribute significantly to top events in the fault trees, and thus, loss of VACP-1 was a low importance to risk. In addition, SEP Topic VI-7.C.1 evaluated the contribution to risk of automatic bus transfers (ABT), specifically, their contribution to loss of power to redundant unit sub-stations 1A2 and 1B2. Backfitting of redundant power supplies for control room indication was not recommended.

PSC 84-018 stated that the current design was acceptable based on the SEP review and acceptance of the design. It is significant to note that the SEP analysis only evaluated VACP-1 from a perspective of providing control room indication and impacting loss of the redundant unit sub-stations 1A2 and 1B2. The loss of VACP-1 was not reviewed for a loss of automatic ESF protective functions. For these reasons, the inspector questioned the conclusion in PSC 84-018.

5.5 Conclusions

The inspector has concluded, based on a review of the regulations, FSAR, and SEP that the safety function of the SGTS is to automatically initiate during accident conditions to mitigate the consequences of these postulated accidents. The licensing basis for this system, as presented in the FSAR, is to automatically initiate when plant conditions exceed preset levels and that no single failure (electrical) can prevent the initiating circuits from performing their protective function. In addition, 10 CFR 50, Appendix A, GDC 41, states that suitable redundancy in components and features shall be provided so that the system's safety function can be accomplished, assuming a single failure.

Although still under review, the current Oyster Creek design for the automatic initiation of the SGTS is potentially susceptible to single failures as it has only one power source, VACP-1 and one initiation logic train downstream of VACP-1. The ability of the SGTS to automatically initiate with a susceptibility of single failure will be carried as unresolved (50-219/88-38-02).

6.0 Rag Found in Scram Discharge Volume

6.1 Event

On 12/30/88, after a reactor scram, the scram discharge volume (SDV) high water level scram signal was bypassed in order to reset the scram logic. Upon reset of the scram logic, the SDV vent and drain valves opened and the "SDV Not Drained" annunciator cleared indicating that the SDV had been drained. Shortly thereafter, while the SDV vent and drain valves remained open, the "SDV Not Drained" annunciator returned for the south SDV header. Eventually, the SDV instrument volume "Hi" and "Hi-Hi" annunciators were also received for that header. These indications showed that even with the SDV vent and drain valves open, water was entering the SDV south header and was not being drained.

The licensee initiated a work request to investigate the inability to drain the south SDV. The inboard SDV drain valve was disassembled and a rag was found to be blocking the line. The inboard drain valve for the north SDV was also disassembled, but no adverse conditions were identified. The source of water was determined to be leaking scram outlet valves, which were subsequently repaired.

As a result of finding foreign material in the SDV, the licensee initiated an effort to fill and drain the SDV five consecutive times in order to verify the ability to drain and to remove any other foreign material. This was accomplished successfully. The amount of time to drain the SDV's was measured with the following results:

	NORTH SDV	SOUTH SDV
1.	5:06	4:28
2.	5:07	4:35
3.	5:07	4:35
4.	5:11	4:35
5.	5:08	4:34

Each filling of the SDV also functionally tested the instrument volume level instrumentation.

The licensee conducted a critique of the event in order to determine the source of the foreign material. Based on the deteriorated condition of the rag, the licensee concluded that it was old and had probably been introduced into the SDV in 1984, when the new SDV system was installed.

6.2 Review of Licensee Actions

Since the licensee's efforts to identify how and when the rag was introduced into the SDV were inconclusive, the licensee's approach was to demonstrate the repeated and consistent ability to drain the SDV. The licensee also desired to perform a visual inspection of the SDV instrument volume while the drain valves were disassembled, using a borescope, but the physical arrangement of the valves made this impossible.

The inspector reviewed the licensee corrective actions and concluded that the five consecutive SDV fill/drains demonstrated confidence in the ability to drain the SDV. They also demonstrated the operability of the instrument volume level instrumentation. The inspector also reviewed the times required to drain the SDV and concluded that a high degree of consistency was demonstrated. These drain down times were compared to those experienced during the most recent plant shutdown. No conclusions could be drawn though, because of the different events measured. The sequence of alarm recorder (SAR) indicates the time of the resetting of the scram contacts, while the five fills/drains were timed from the last SDV drain valve's opening.

During this outage, a modification was performed on the scram discharge volume, installing cleaning connections near the end of each of the six headers located above the hydraulic control units. The inspector reviewed Short Forms #44841, #44842 and #44840 in order to assess the cleanliness control measures implemented for this modification.

Installation specification, OC MM 328155-001 specified that all material be maintained in a Class C cleanliness state as defined by ANSI N45.2.1. In addition, it specified that the internals of pipe added by this modification shall be flushed. During the modification, a Field Change Request was submitted requesting deletion of the flushing requirement based upon maintaining Class C cleanliness during erection. This request was approved and no flush was performed on the new cleaning connections after they were welded to the SDV.

The inspector reviewed the work packages and quality assurance inspections and verified that Class C cleanliness was documented until the piping assembly was welded to the SDV header, at which time no more internal visual inspections were possible.

NRC Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning Fluids Systems and Associated Components of Water Cooled Nuclear Power Plants," essentially incorporates for operating nuclear power plants, the provisions of ANSI N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants," both of which are committed to by the licensee in the Operational Quality Assurance Plan.

ANSI N45.2.1-1973 states that it is its intent to maintain the specified level of cleanliness during erection so that only water flushing will be required for final cleaning. This indicates that the maintenance of cleanliness during erection does not provide justification for deletion of the requirement to perform a water flush. Based on these requirements, as stated in ANSI N45.2.1-1973, the inspector concluded that the change to the installation specification to waive the flushing requirement was not proper, and that SDV Class C cleanliness has not been demonstrated by examination of flushing filters.

The inspector also reviewed licensee Procedures A100-SMM-3900.07, "Maintaining Class C Cleanliness," and A100-GMM-3900.06, "Maintaining Class C Cleanliness," for implementation of the cleaning requirements of ANSI N45.2.1-1973. These procedures incorrectly reference the 1980 edition of ANSI N45.2.1, which has substantially different flushing requirements from the 1973 edition. Since the licensee's QA plan delineates Regulatory Guide 1.37, which endorses the 1973 edition of ANSI N45.2.1, the licensee is committed to the 1973 requirements (as modified by the OQA). Discussions with QA personnel indicated that it is not unusual for the flushing requirements to be waived based on maintenance of cleanliness during erection. The inspector concluded that the licensee's procedures were not adequate in that they do not implement the cleaning requirements of ANSI N45.2.1-1973.

The licensee's deletion of the system flushing requirement from the SDV modification and the licensee's programmatic implementation of the cleaning requirements of ANSI N45.2.1-1973 will be an unresolved item (50-219/88-38-03).

7.0 Air Accumulator Testing

The licensee conducted testing on the air accumulators to various safety related air operated valves during this report period. This testing was conducted in response to concerns identified by the Oyster Creek Emergency Operating Procedure (EOP) Inspection (IR 50-219/88-200) and Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety Related Equipment. The EOP Inspection had identified deficiencies in the method by which the containment ventilation exhaust valves, V-27-1 and V-27-2, and intake valves, V-27-3 and V-27-4, were tested. The testing method as identified by the EOP inspection does not verify that the accumulator check valve would seat and be leak tight upon loss of instrument air nor verify that the accumulator had a sufficient free air volume available to stroke the valve under design conditions. The Oyster Creek instrument air system is not a safety related system.

In the original scope of the accumulator testing, the licensee identified eighteen accumulators which they intend to test during this outage. These accumulators affect containment isolation, the Standby Gas Treatment System (SGTS) and condensate makeup to the isolation condensers. The inspectors have closely followed licensee testing activities. An additional 22 accumulators which are associated with SGTS valves were planned to be accomplished by the end of the next refueling cycle.

Presently, the licensee has tested sixteen of the eighteen accumulators. Of the sixteen accumulators tested, eight accumulators required corrective maintenance. Four of the accumulators which required work provide an air supply to the main steam isolation valves (MSIV), and the other four accumulators which required work provide an air supply to the SGTS trains' inlet and outlet valves.

The accumulators and associated piping to the MSIVs provide an air supply to assist in seating the valves upon a loss of instrument air. Previous local leak rate tests have shown that if no air is supplied to the MSIVs in the shut direction, the valves will not pass the local leak rate test acceptance criteria. This fact was identified in Preliminary Safety Concern 88-07 which was written in January 1988 but is not yet resolved. The accumulator piping to the MSIVs consists of brass pipes and fittings. While attempting to perform the test on these accumulators, the licensee discovered that there was excessive leakage from these fittings. The procedure had specified that all fittings were required to be snooped and the leakage corrected; however, due to the large number of fittings which were leaking air, the procedure could not be completed. The licensee subsequently performed an air pressure drop test on the accumulator and associated piping to quantify the leakage. The air pressure in the accumulator had dropped from 100 psig to 40 psig in a half hour period. The licensee evaluated the brass piping design to be inadequate and is presently modifying the piping by replacing the brass piping with steel piping and welding the steel piping together instead of utilizing fittings. The licensee has also concluded that this piping must meet seismic requirements and is presently installing seismic supports to the piping.

The accumulators to the SGTS train inlet and outlet valves provide the motive force to shut the valves upon a loss of instrument air. The absence of accumulators upon a loss of instrument air would result in the standby SGTS train's inlet and outlet valves failing open. Since the SGTS trains share a common header downstream of the outlet valves of each train and upstream of the inlet valves of each train, the operating SGTS flow will recirculate backwards though the standby SGTS train, thereby rendering the operating SGTS ineffective. During the testing of these accumulators, the licensee determined the pressure drop in the accumulators and associated piping to be excessive. In an attempt to reduce the air leakage rate, the licensee replaced the isolation check valves to the the accumulators. The replacement of the check valves reduced the air leakage to a 1.5 psig to 3.0 psig pressure drop from 100 psig over a 30 minute period. The licensee, however, has evaluated this reduced leakage still to be unacceptable to ensure that the accumulators can perform their design function. As a result, the licensee is presently replacing the valve operators on the valves to further reduce the air leakage rate. The licensee is continuing their evaluation of the test result and considering changes to their SGTS procedures to ensure that the SGTS will perform its design function.

The licensee has not completed their evaluation of the test results. Plans, however, are underway to review all forty accumulators for seismic requirements. The licensee has not decided whether further accumulator testing on other accumulators are necessary. The inspector asked based upon the high percentage of maintenance work required as a result of accumulator testing to date and the questions concerning the ability of the valves to perform their design function, if the remaining accumulators should be tested prior to restart from the outage. The inspectors will continue to follow the licensee's actions. This item is unresolved (50-219/88-38-04).

8.0 Monthly Maintenance Observation

Portions of the following maintenance activities were observed.

-- Accumulator testing on Containment Ventilation Exhaust Valves, V-27-1 and V-27-2.

-- Troubleshooting of Main Steam Isolation Valve, NS03A, to determine cause for local leak rate testing failure.

-- Repair of Feedwater Check Valve, V-2-72.

Items inspected included a review of pertinent work packages, observation of valve tagouts, verification that technical specification requirements for secondary containment were satisfied, appropriate radiological precautions were taken in accordance with the Radiation Work Permit, required administrative approval was obtained prior to the start of work and quality assurance hold points were observed.

The accumulator test on valves V-27-1 and V-27-2 involved the disassembly of the accumulator from its associated piping and seismic supports to verify that there was no water accumulation. It was noted during the reinstallation of the accumulator that the work package did not specify any torque specifications for the strap bolts which held the accumulator to its seismic support. The inspector reviewed the original installation specification for the modification and noted that the installation specification listed torque values for these bolts. The inspector identified this fact to the licensee. The licensee subsequently changed the work package to torque these bolts in accordance with the installation specification.

Although further discussion with the Technical Functions personnel raised questions on whether or not torque values were in fact required for these bolts, it was evident that the requirement for torque values for the reinstallation of these bolts was not considered. The inspector had no further questions on this matter.

9.0 Monthly Surveillance Observations

9.1 Source Range Monitor Front Panel Test, Procedure 620.4.004.

As a result of the frequent short periods which were observed on the source range monitors (SRM), the inspector observed the performance on the SRM Front Panel Test. The short period alarm was jumpered out of service during this period of time. A review of the licensee's evaluation to refuel without this alarm function was performed. It was also noted on the surveillance that this alarm was tagged out of service and that the Rod Block alarm was locked in as a result of the Refueling Bridge being tagged out of service. The test data were observed to be within the Technical Specification acceptance criteria. Proper approval from the Group Shift Supervisor was obtained prior to the start of the surveillance. No unacceptable conditions were identified.

9.2 Reactor Triple Low Water Level Test and Calibration, Procedure 619.3.006.

Portions of the Reactor Triple Low Water Level Test and Calibration surveillance were observed from the control room and at RK02. Review of this surveillance included the verification of test instrument calibration, test values were within the acceptance criteria, appropriate administrative approval received and proper documentation performed. No unacceptable conditions were identified.

10.0 Backshift Inspection

NRC inspection of licensee activities during deep backshift hours were conducted on the following dates:

-- Saturday, December 31, 1988
-- Thursday, January 5, 1989
-- Friday, January 6, 1989
-- Saturday, January 14, 1989

Areas of inspection included the observation of fuel loading in the reactor vessel, fuel pool gate gasket replacement, Source Range Monitor Front Panel Testing, control room activities and performance of plant tours.

11.0 Reactor Vessel Lost Parts

During this outage, a large number of items had inadvertently fallen into the reactor vessel. These items include two bullet lights, a Hansen air fitting, a magic marker cap, a metallic band, a metallic ring, a "screen-like" material, an acorn nut, a lens cap, a lens to a pair of safety glasses, three pieces of tie wrap and a few short pieces of duct tape. Although a majority of these items have been removed from the reactor vessel, the licensee intends to leave some of these items in the reactor vessel during the upcoming operating cycle. These items include a few short pieces of duct tape, a lens to a pair of safety glasses and a lens cap. A General Electric analysis was presented to show that the items would disintegrate upon heatup and that chemistry changes were acceptable.

The inspector reviewed portions of the licensee's Reactor Vessel Lost Parts Analysis. This analysis includes a reference to the General Electric Lost Part Analysis which was performed for the licensee during the 10R Outage. No concerns were identified by the inspector in the review of General Electric's evaluation. In light of the large number of items which have fallen in the reactor vessel during this outage and the fact that many items in the reactor vessel were identified by use of an underwater camera device the persons who may have inadvertently and unknowingly dropped the items, improvement in the observation of cleanliness during maintenance and operational activities is needed. Licensee staff members acknowledged the need for improvement and agreed to review their practices.

12.0 Torus Tiedown Bolts

Independent visual examinations were conducted by the licensee and the inspector on the torus anchor bolts. This examination was conducted in response to anchor bolt anomalies identified in the Hatch Nuclear Plant's Mark I containment. The majority of the anchor bolts at the Hatch plant were deformed with a maximum deflections between 1/4 inch and one inch.

The visual examination of the anchor bolts at Oyster Creek included checking for deformation in the saddles, bearing plates, base plates, anchor bolts and grouting. Positions of the bolts in the slotted holes were also noted. The licensee examined 90% of the anchor bolts and identified no deformation or anomalies. The inspector examined 20% of the anchor bolts with similar findings. The inspector had no further questions regarding this matter.

13.0 Fuel Support Castings

During the replacement of fuel support castings (pieces) in the control rod drive tubes, the licensee experienced difficulty in properly seating the castings. The licensee had removed 26 castings earlier in the outage to support the exchange of control rod blades. Most of these 26 castings were not properly seated. Additionally, the licensee believed that three peripheral castings were not fully seated.

After unsuccessful attempts to seat the castings, the licensee contracted General Electric to assist in the seating of the castings. With General Electric assistance, the licensee was able to seat all castings. One of the castings, however, required minor filing to allow the guide pin on the lower core support plate to fit into the casting. Further evaluation of the three peripheral castings indicated that two of the castings were fully seated. The third casting was easily seated after it was slightly touched. The licensee determined that this casting may have lifted off its seat when its fuel bundle was removed from the core.

The licensee believes that a potential contributor to the difficulty in seating the castings was the fact that some castings were not returned to their original positions. Although these castings are supposedly identical, the licensee hypothesized that they may have become form fitted in their positions in the core plate. In previous outages, the castings were returned to their original position as a result of the method of exchanging control rod blades, and thus no fit problems existed. The licensee was able to obtain an original plant drawing showing the uniquely numbered castings in their original core position. Utilizing the serial numbers enscribed in the castings, the castings were returned to their original positions.

It was observed, however, that some of the castings which the licensee had difficulty seating were already in the original position. It appeared to the inspector that operator technique was also a potential contributor to the difficulties in seating the castings. General Electric personnel had experienced a easier effort in seating the castings. Another potential contributor to the seating difficulty was the weight of the tool utilized to seat the castings. The licensee believes that use of a heavier tool would have assisted in properly seating the castings.

After seating the castings, the licensee verified that all castings which were moved during the outage were properly seated. Additionally, more than sixty other castings which were not moved were verified to be fully seated. The inspector had no further questions regarding this matter.

14.0 Control Rod Drive Return Line Piping

On December 28, 1988, while performing weld inspections on the control rod drive return line, the licensee identified that a section of piping was significantly thinner than called for in Revision 6 of the General Physics Inservice Inspection Program Schedule (ISIPS). The ISIPS had called for a schedule 80 piping which has a nominal thickness of 300 mils. The portion of piping, however, had readings between 200 mils and 220 mils.

This portion of piping is located between the CRD return line manual isolation valve, V-15-29, and weld NC-4-20 and forms part of the reactor pressure boundary. The piping is a 3 inch pipe six inches in length. The licensee's evaluation of this piping determined that it was not thinned from erosion. This evaluation was based upon the uniform thickness of the piping and the abrupt change in wall thickness at the location of weld NC-4-20. The evaluation further postulated that the piping was probably installed schedule 40 piping during original plant construction, although no installation documentation can be located. The licensee performed a stress analysis on the schedule 40 piping and determined that it was acceptable in accordance with ANSI B31.1. The inspector reviewed the licensee's evaluation of pipe stresses and identified no unacceptable conditions.

15.0 Loss of Security Electrical Loads

On December 10, the licensee was preparing to perform maintenance to replace a breaker which supplies safeguards loads. Upon deenergizing the safeguards loads, security personnel realized that compensatory actions could not be maintained because of the unanticipated loss of certain safeguards functions. As a result, the security loads were reenergized almost immediately and the maintenance activities deferred.

The inspector interviewed operations and security personnel concerning the circumstances surrounding this event. Operations personnel had believed that security personnel maintained a set of safeguards electrical diagrams and that they were cognizant of the loads which would be lost upon performance of this maintenance. On the contrary, security personnel did not have such diagrams in their possession and stated that even if they did have them they did not have adequate knowledge to utilize them. Security personnel had relied on memory to determine what safeguards equipment they would lose.

It was evident that the miscommunication resulted in an inadequate review of the impact of the maintenance activity. The safeguards engineer at the plant was not informed nor consulted in the performance this work. It was also noted from interviews with personnel that this practice had occurred many times in the past, however, appropriate compensatory measures were taken.

The inspector brought this problem to the attention of the licensee. Although a formal critique was not performed the licensee held a meeting with the different departments involved. The licensee intends to generate a list of safeguards loads and their associated power supplies for use after this outage. It the interim, an increased awareness of the problem and the utilization of the safeguards engineer should prevent simiiar occurrences and not jeopardize plant security.

The inspector had no further questions regarding this matter.

16.0 Source Range Monitor Log Integrator Cards

During pre-refueling checks the licensee found defective log integrator cards in the source range monitors (SRM). These log integrator cards were replaced prior to refueling, but after the card replacement the SRM's exhibited frequent large spikes coupled with short period alarms. Prior to refueling, the inspectors discussed a concern regarding SRM operability with the Plant Engineering director. The licensee explained that they had delayed refueling for approximately five hours to trouble shoot the SRM's and found no problems. The inspector reiterated his concern regarding SRM operability and the large number of short periods. The licensee stated that with regard to refueling, the SRM's were operable to accurately measure neutron level. The inspector agreed to review SRM behavior after some fuel assemblies had been loaded in the core around the SRM's. After this had occurred, the SRM still exhibited the same behavior. In addition, when one source was moved adjacent to SRM 21, a normal source range response was observed and did not display the abnormal spiking prevalent with SRM's 22, 23 and 24. Again the licensee determined that the source range instrumentation was adequate to measure source level neutrons during refueling.

Subsequent to refueling the licensee performed troubleshooting of the SRM's to include response time testing of the log integrator cards. The licensee conducted bench testing of the log integrator cards removed from the SRM's after completing refueling operations. The licensee determined that the 390 microfarad capacitors used in the log integrator dampening circuit were defective.

These log integrator replacement cards with the defective 390 microfarad capacitors were obtained from shop spares and bench tested prior to plant installation. Inspection Report 50-219/88-33 identified a violation regarding

ANSI/ASME N45.2.2, storage of QA spare parts onsite outside the warehouse and raised a concern regarding reliability of these spare parts due to the inadequate storage. During the 88-33 inspection the licensee assured the inspector that before any shop spares would be used in the plant sufficient bench testing would be conducted to verify the acceptability of the spare part. This event raises the question of the acceptability of the QA process used to verify shop spare part adequacy for plant installation and also raises the question of previous shop spare part installation in the plant.

Another concern results from the guidance provided by the technical manual with regard to the correct replacement module number. Apparently the technical manual provided different module numbers on the functional block diagram, the SRM applicability table and the manual section on operation and troubleshooting of the log integrator. In addition, the one module number indicated is for a process radiation monitor with a difference in the card capacitance which explains the large spikes and short period alarms exhibited by the SRM's. The inspector questioned whether the technical manual could provide sufficient guidance to the technician to repair safety instrumentation and control circuitry. The licensee critiqued this event. This item is unresolved pending further NRC review (50-219/88-38-05).

17.0 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to Technical Specification requirements were examined by the inspectors. This review included the following considerations: the report includes the information required to be reported to the NRC; planned corrective actions are adequate for resolution of identified problems; and the reported information is valid.

The following reports were reviewed:

-- Monthly Operating Report for November 1988

-- Special Report 88-01, Fire Diesel Pump 1-2

  This report identified nonfunctional fire diesel pump 1-2 due to debris in the suction bell, which degraded pump performance. A rag was found in the suction bell, but the licensee was unable to determine how it was introduced into the system. The licensee offers that a potential introduction point is through inspection ports on the relief valve. The inspector was unable to understand how a rag introduced in the system at a relief point could happen to partially block the pump suction. System material cleanliness requirements during maintenance should be reviewed by the licensee. The inspector had no concerns.

18.0 Meetings

18.1 General Review Board Meeting

The inspectors attended portions of the General Office Review Board meeting conducted at Oyster Creek on January 10 and 11, 1989. The meeting appeared to be a very worthwhile effort to improve plant and company performance.

18.2 Quality Maintenance Team Briefing

On 12/21/88, resident inspectors met with a maintenance manager and were briefed on the licensee's plans to enhance maintenance performance. The plans include the initiation of a pilot program using the Quality Maintenance Team (QMT) concept with eventual full implementation of the QMT concept.

19.0 Radiation Protection

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 to verify that personnel complied with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area.

20.0 Observation of Physical Security

During daily tours, the 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. The inspectors examined vital area access points to verify that they were properly locked or guarded and that access control was in accordance with the security plan.

21.0 Review of Licensee Event Reports (LERs)

21.1 In-Office Review of LERs

A review was conducted of LERs submitted to the NRC to verify the details were clearly reported, the cause appears accurate and is supported by report details, corrective actions appear to be appropriate, and that no further information is required. The following LERs were reviewed:

87-34: Inadequate emergency lighting was identified to exist in several areas. Additional lighting to correct the condition has been installed.

87-35: Reactor scram with the reactor shut down during the performance of a surveillance test. The cause was attributed to a degraded cable connection due to normal wear. The cable will be repaired and similar conditions inspected.

87-36: Improper control of a high radiation area due to personnel error and procedural noncompliance. Several workers were terminated and stricter guidance was issued.

87-37: Failure to perform two monthly gaseous effluent dose calculations due to personnel error. Subsequent calculations showed releases to be well below the limit. Corrective action consisted of training additional personnel to perform the calculations.

87-39: Discovery of a failure to meet 10 CFR 50, Appendix R criteria in an emergency diesel generator lockout relay circuit. Corrective action was taken to modify the circuitry to comply with 10 CFR 50, Appendix R criteria.

87-4[illegible] Torus oxygen sample line isolation valves were identified as not meeting single failure criteria. Modifications will be made to isolation valve circuitry to meet single failure criteria.

87-41: (Voluntary Report) Fuel pool cooling system piping radiation shielding inadvertently removed creating a high radiation area. Properly labelled permanent shielding was installed and personnel training was conducted.

87-42: This event was discussed in Inspection Report 50-219/87-33.

87-46: (Voluntary Report) This event was discussed in Inspection Report 50-219/87-33.

88-01: This event was discussed in Special Inspection Report 50-219/88-02.

88-02: Containment high range radiation monitors failed to meet acceptance criteria during calibration due to incorrect post installation testing. The monitor was repaired, tested and returned to service, a vendor document control program established, and personnel training conducted.

88-03: Containment particulate monitor sample line isolation valves control circuitry found not to meet single failure criteria since installation in 1976. Standing orders have been issued until the deficiency is corrected in accordance with the Integrated Living Schedule.

88-04: Isolation condenser automatic actuation pressure sensors tripped at valves greater than those specified in Technical Specifications. The sensors were adjusted to trip within setpoint limits. Long term corrective action is to replace the instruments with an analog trip system.

88-05: A tagging error caused components of both standby gas treatment systems to be inoperable. Corrective action consisted of additional personnel training. This event was reviewed in Inspection Report 50-219/88-09.

88-06: During surveillance testing, four of eight isolation condenser pipe break sensors tripped at a differential pressure greater than specified in the Technical Specifications. The sensors were adjusted to trip within units. Four sensors will be replaced during the current outage with newer design switches and their performance evaluated.

88-09: During surveillance testing, two isolation condenser automatic actuation pressure sensors tripped at valves greater than specified in the Technical Specifications. Corrective action is the same as described in LER 88-06.

88-11: This event was reviewed in detail in Inspection Report 50-219/88-21.

88-14: Testing showed Main Steam Isolation Valve NS04A leaked excessively. The valve was repaired, a new valve stem was installed, and a successful leak rate test performed. The valve inspection and repair procedure will also be revised.

88-15: A main steam isolation valve closure occurred during surveillance testing, while the plant was in cold shutdown. The valve closure occurred with a required jumper fell off and shorted to ground. A project has been initiated to eliminate the need for installing jumpers during surveillance testing.

88-16: During surveillance testing, four isolation condenser automatic actuation pressure sensors tripped at values greater than those specified by the Technical Specifications. The corrective action is the same as that specified in LERs 88-04 and 88-05.

88-17: (Voluntary Report) Three control rod accumulators low pressure alarms were present for greater than one hour in violation of plant procedures. The event was discussed with all operating shift personnel.

88-18: Inadvertent actuation of the "B" isolation condenser due to operator error. The operator immediately realized his error and took corrective action. The actuation lasted for less than seven seconds. This report was made required reading for operators.

88-19: This report described the circumstances associated with both isolation condensers being inoperable. An enforcement conference was held relative to this matter. The enforcement conference is discussed in Inspection Report 50-219/88-33.

88-21: This report described the circumstances associated with both isolation condensers being in an unanalyzed condition. A special review of this event was conducted by an Augmented Inspection Team. Results of the team review are documented in Inspection Report 50-219/88-80.

88-22: This report described the loss of an emergency bus due to a ground fault. This event was reviewed in Inspection Report 50-219/88-80.

88-23: Drywell airlock not leak rate tested in accordance with Appendix J. The review of this event is discussed in Inspection Report 50-219/88-28.

88-24: Main steam isolation valve closure signal occurred during surveillance testing due to procedural deficiency. The surveillance procedure will be revised.

88-26: A reactor scram signal was received with the plant shutdown due to an error in a newly revised procedure. The procedure will be revised and this LER made required reading for qualified reviewers.

88-27: Several fire watch tours were missed due to inadequate guidance and direction being provided to temporary contractor employees. Corrective action consisted of establishing a log which requires hourly signatures. Also, a procedure will be developed which will define fire watch responsibilities and the log requirements.

88-29: Six containment isolation valves were identified which do not meet NUREG-0737 criteria which requires deliberate operator action to open an isolation valve after the isolation signal is reset. A modification will be performed on these valves so they will meet requirements in accordance with GPUN's Integrated Living Schedule.

21.2 Onsite Review of Licensee Event Reports (LERs)

The following LERs were reviewed to determine the report was adequate in assessing the event, the cause appeared accurate, corrective actions appeared appropriate, generic applicability was considered, and that the licensee review and evaluation were complete and accurate.

87-33: Safety limit violation caused by personnel error while removing reactor recirculation pumps from service. This event was discussed in detail in Inspection Report 50-219/87-29. During the event, it was noted the fuel zone level monitor (F2LM) did not activate when all five recirculation pumps were tripped. Corrective actions specified in this LER and also discussed in a September 20, 1987 letter, Clark to Murley, were: "GPUN will evaluate the fuel zone water level instrumentation system for the appropriateness of the recirculation pump trip signal and the possible addition of an alarm." During this inspection, the licensee's committed-to evaluation of this matter was reviewed. A Licensing Action Item (LAI) 87178.06 was written to initiate this evaluation. This LAI was closed out on December 7, 1987, based on the performance of an evaluation. The inspectors review of this evaluation showed that it dealt with a February 1987 event in which a recirculation pump M-G set field relay failed and did not at all address the corrective actions specified in the LER. The performance of an inappropriate evaluation and its apparent acceptance was discussed with the licensee. Subsequently, a supplemental response to the LAI, dated January 16, 1989, was prepared to address the F2LM, and concluded the installed instrumentation is adequate. Also, the evaluation of an alarm installation was stated to have been completed and determined no alarm was necessary. The written evaluation associated with the alarm determination was not available on site. Additional management attention to the review of committed-to evaluations appears to have been warranted in this instance to assure that a correct evaluation was performed.

87-45, 88-08, and 88-10: These three LERs all reported standby gas treatment system automatic initiations. The basic cause of all events was water in the off gas inlet line and its associated drain to a sump located at the base of the stack. In addition to procedure changes, personnel counseling on the importance of strict performance compliance, and the required reading of two of the reports by Radwaste Operations personnel, a modification to the off gas drain was made and a new seal pot was installed to increase the water level over the drain line. This modification should eliminate this problem which had been experienced for a long time.

87-48: This LER reports a reactor scram signal which occurred while moving the reactor mode switch from shutdown to refuel during testing. This apparent cause was attributed to mechanical wear of the mode switch. Corrective action included an evaluation of a mode switch replacement during a future refueling outage. This evaluation has been completed and it was recommended not to install a new mode switch at this time. The licensee has, however, committed to purchase a new improved mode switch. One of the reasons for not installing a new mode switch is that there is no clear evidence a problem exists with the installed switch. The inspector had no further questions relative to this matter.

88-07: This report describes the discovery of a reactor coolant sample line containment isolation valve being inadequately supported. It was reported the valve was supported by rope and a pipe support upstream of the valve was broken. In addition to correcting the physical deficiencies, corrective action consisted of making this LER required reading to all plant engineering personnel. During this inspection, it was determined additional corrective action was taken in that a critique of the event was performed which identified root causes and specified additional corrective actions. The inspector had no further questions relative to this matter.

88-12: This report describes certain Appendix R deficiencies identified in electromatic relief valves and cleanup system valves circuitry. Part of the analysis and safety assessment of the occurrence described the use of torus cooling using the containment spray system dynamic test mode and the emergency service water system. The use of this method of torus cooling is affected by a Preliminary Safety Concern (87-003) which describes certain elements of the containment spray system logics during the dynamic test mode. The PSC explains that the capability of the dynamic test mode to cool the torus from the control room may not be available due to logic circuit considerations. The inspectors felt this consideration was not addressed in the LER. The Preliminary Safety Concern (PSC) had been closed out but because of recent interest in PSCs was stated by the licensee as being reevaluated. The resolution of this matter is being tracked by Unresolved Item 50-219/87-04-02.

88-13: This report describes a Main Steam Isolation Valve (MSIV) stem failure. As part of the description of the event, the licensee described a Technical Specification violation in that a half scram was not inserted for approximately 50 minutes while there was no steam flow in the "A" steam line with both MSIVs indicating open. The decision not to insert the half scram was made for safety concerns to permit a maintenance foreman to inspect the outboard MSIV. The LER states when it was determined, the foreman was clear of the outboard MSIV, the half scram was inserted. This statement is not entirely true for, based on discussions with personnel and an entry in the log book, the half scram was in fact inserted, based on information developed during the evaluation before the outboard MSIV was inspected.

Since many options were available to the crew such as believing the outboard valve position indication and not inspecting the valve to removing the half scram for only the two or three minutes the outboard valve was being inspected. The failure to insert the required half scram was discussed in detail with members of the onshift crew during the event and with licensee management. From these discussions, it was determined management above the shift level made the decision not to insert the half scram for personnel safety considerations. Certain levels of management and members of the shift crew, during the event immediately recognized and expressed the view that a half scram must be inserted. The Group Shift Supervisor (GSS) was aware that someone had been dispatched to inspect the outboard MSIV but it could not be determined who actually required the inspection be performed. After being dispatched, the foreman could not be contacted by radio or pager.

The inspectors discussed the failure to insert the half scram, and the details associated with the decision with licensee management. During this discussion the need to minimize disagreement during shift operation and to effectively control the dispatching of personnel which could have an effect on decisions which have a potential to affect Technical Specification requirements was identified. It is realized that during an event the time to make decisions is limited. However, events of this nature should be evaluated in order to more effectively address possible future events. The licensee indicated the event had been reviewed and that the GPUN letter describing command responsibilities had been re-emphasized with the GSSs. No enforcement action relative to the delayed insertion of a half scram when its insertion was indicated is going to be taken since it was identified by the licensee and met the criteria of 10 CFR 2, Appendix C (50-219/88-38-06).

88-20: This report describes the discovery that the isolation condenser steam vents and the emergency service water discharge lines from the containment spray heat exchangers radiation monitors would not fulfill their design function of radiation leak detection due to high radiation background following an accident. During this inspection the inspector reviewed the four alarm response procedures associated with these monitors, of the four procedures involved only one had a note included which indicated the monitor was subject to high background radiation and may alarm without a leak being present. The necessity of upgrading procedures to reflect discoveries made which could have an affect on operator responses was discussed with licensee management. Management immediately took steps to insure that reviews are conducted of LERs to assure that appropriate procedures are changed if necessary.

22.0 Refueling Activities

Refueling began on January 6, 1989 and was completed on January 13. This refueling was conducted without any error. The only problems observed were those associated with Source Range Monitors (Sections 9.1 and 16.0). This smooth and error-free refueling is in contrast to the earlier defueling described in Inspection Report 50-219/88-33. The significant improvement is the result of the application of lessons learned from refueling and the considerable management attention paid to the refueling.

23.0 Unresolved Items

Unresolved items are matters for which more information is required in order to ascertain whether they are acceptable, violations, or deviations. Unresolved items are discussed in paragraphs 1.0, 5.0, 6.0, 7.0 and 16.0 of this report.

24.0 Exit Interview

A summary of the results of the inspection activities performed during this report period were made at meetings with senior licensee management at the end of this inspection. The licensee stated that, of the subjects discussed at the exit interview, no proprietary information was included.