U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	94-03
Docket No.	50-219
License No.	DPR-16
Licensee:	GPU Nuclear Corporation 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Inspection Period:	January 24, 1994 - March 7, 1994
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Inspection Summary: This inspection report documents the safety inspections conducted during day shift and backshift hours of station activities including plant operations, maintenance, engineering, plant support, and safety assessment/quality verification. The Executive Summary delineates the inspection findings and conclusions.

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EXECUTIVE SUMMARY

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Plant Operations

GPUN continued to operate the unit safely. Overall, control room operator response to two unexpected plant transients was very good. One exception was the use of an inappropriate method to control reactor vessel level by increasing reactor recirculation pump speed. While weaknesses in administrative controls contributed to a condition in which the alternate emergency diesel generator fuel oil supply became unacceptably low, operations personnel implemented appropriate actions to restore level and to prevent recurrence. The operations department implemented effective actions in response to recent NRC concerns relating to declaring certain components/systems inoperable during surveillance testing.

Maintenance

The maintenance and surveillance testing activities during this inspection were generally conducted safely by knowledgeable personnel. However, an inadequate pre-job review of a maintenance activity on the feedwater control system resulted in a plant transient, and is a violation of NRC requirements. Station management responded promptly and appropriately to several industrial safety performance concerns identified by the inspector. In one instance during surveillance testing, the licensee's failure to perform a physical verification appeared to be inconsistent with the circumstances.

Engineering

The onsite engineering organization properly prioritized and executed work activities. Station documents, including Technical Specifications, the Final Safety Analysis Report and operating procedures were found to be in conflict in identifying containment isolation valves; this item is unresolved to determine whether sufficient administrative controls are in place to ensure that Limiting Conditions for Operation (LCO) are applied for the appropriate isolation valves; no LCO violations have been identified to date. Corporate engineering responded appropriately to a concern related to potential stress loading of the primary containment structure.

Plant Support

Periodic inspector observation of station workers and Radiological Controls personnel noted proper implementation of radiation controls and protection requirements. The inspectors observed that Security Program requirements were properly implemented by the licensee.

Safety Assessment/Quality Verification

The licensee failed to implement timely and effective actions to identify and correct the presence of apparent strainers in plant systems, and is a violation of NRC requirements.

DETAILS

1.0 PLANT OPERATIONS (71707, 93702)

1.1 Operations Summary

The unit operated at or near full power during the inspection period, except for a two day power reduction to perform full closure testing of main steam isolation valves, to complete preventive maintenance of the "D" reactor recirculation pump motor generator, and to clean main condenser tubes.

1.2 Facility Tours

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

- control room
- cable spreading room
- diesel generator building
- new radwaste building
- old radwaste building
- transformer yard
- intake area
- reactor building
- turbine building
- vital switchgear rooms
- access control points

Control room activities were found to be well controlled and conducted in a professional manner. The inspectors verified operator knowledge of ongoing plant activities, equipment status, and existing fire watches.

1.3 "B" Reactor Recirculation Pump Motor Generator Trip

On March 3, 1994, at 2:34 p.m., the "B" reactor recirculation pump (RRP) motor generator (MG) tripped. The "B" loop flow decreased to zero in about five seconds. The unit was operating at 100% power. The plant responded normally with a level swell of about 7 inches and power stabilizing at about 90 percent. Control room operators idled the loop in accordance with abnormal operating procedure ABN-3200.02. Troubleshooting activities by electrical maintenance personnel determined the cause of the trip to be a loss of generator field. They also identified a finger-tight connection on the power input lead of the generator field brush rigging. Although the finger-tight connection could have caused the loss of field, it was not conclusive since the connection did not exhibit any arc burns to indicate that it had broken contact. The connection was tightened and other connections were checked. Electrical maintenance checked and cleaned exciter brushes and slip rings. No other possible causes of the trip were identified. The MG set was restarted, and all readings were normal. The MG set had been operating in a stable manner before the trip and on subsequent restart. At 7:56 p.m., the "B" RRP was started. The unit was returned to full power at 9:20 p.m. No further problems have been observed to date with the "B" MG set.

The inspectors, the system engineer and his supervisor, and the electrical foreman held further discussions concerning the event on March 4, 1994. The troubleshooting activities of the previous evening were discussed as noted above. The inspector had one additional question concerning the actual trip setpoint of the undervoltage relays. The licensee provided information showing that the relays had been adjusted during December 1992. They had been set at 16, plus or minus 1 volt (normal field voltage is 40 to 50 volts DC). The inspector concluded that the licensee adequately evaluated this event and that control room operators responded appropriately.

1.4 Plant Transient Resulting from "B" Feedwater Flow Instrument Calibration (Violation 50-219/94-03-01)

On March 7, 1994, at 11:24 a.m., while operating at full power, the plant experienced a transient when the "B" feedwater regulating valve (FRV) unexpectedly closed during the performance of a calibration of the "B" feedwater flow transmitter. Control room operators responded quickly to the resulting decrease in reactor vessel water level to take manual control of the master FRV controller and to reduce reactor recirculation pump (RRP) speed in order to lower reactor power. The operators also informed the instrumentation and control (I&C) technicians to return simulated feedwater flow to zero. Reactor water level then began to increase rapidly, to about 167 inches above the top of the active fuel (TAF). Normal level is 160 TAF. The operator increased RRP speed slightly to remove some of the water in the annulus to prevent a turbine trip/reactor scram on high reactor water level (175 inches above TAF). Although the increased RRP speed had minor impact on the transient, it was not appropriate to use RRPs as a method of level control because it differs from existing operator training guidance. The RRP control system is a power/flow control system, not a level control system, although a secondary effect from flow changes is an initial level change. The inspector concluded that overall the operators responded well to the transient. Prior to stabilizing the plant, reactor power reached 96 percent, primarily due to the addition of relatively cool feedwater. This condition was 2 percent below the flow biased average power range monitor trip point. A reactor half-scram was received. Reactor power was stabilized at about 88 percent, and feedwater control was returned to normal (3 element control) before returning to full power at 12:46 p.m.

Subsequent review and discussions of the above event disclosed that the "B" FRV closed when the I&C technicians simulated a "B" loop feedwater flow that was above the feedwater pump runout flow protection value. The job order (No. 47790) consisted of an instrument calibration data sheet, and specified placing the feedwater control system in single element control, which was thought to remove the runout protection from the circuit. The calibration, as specified, had always been performed when shutdown. This was the first time it had been performed at power and was being conducted because the operators noted a difference between the local feedwater flow indication and the control room indication. Discussions with the I&C superintendent indicated that he and other I&C personnel were aware of the feedwater pump runout protection circuit; however they thought it was bypassed when in single element control. The I&C personnel reviewed the associated feedwater control prints but did not identify that the runout protection circuit was not bypassed in any mode of feedwater control operation. The only way to defeat the FRV runout closure feature is to pin the valve so it cannot physically move.

10 CFR 50, Appendix B, Criterion VI (Document Control), requires that measures shall be established to assure that documents, including changes, are reviewed for adequacy. Job order No. 47790 was not adequately reviewed in that it did not identify that the runout protection was not disabled when in single element feedwater control, which resulted in an unnecessary plant transient and a challenge to the control room operators. The inspector identified that there were two previous NRC violations of a similar nature wherein an inadequate technical review was performed, and resulted in a challenge to personnel and/or the plant (NRC Inspections 50-219/93-28 and 50-219/93-80). Failure to perform an adequate technical review of the proposed maintenance activity is a violation of the above requirements. The continuing nature of this type of violation indicates a lack of aggressive management attention to resolve the noted concerns. **(VIO 50-219/94-03-01)**

1.5 Alternate Diesel Generator Fuel Oil Supply Below Design Basis

On February 12, 1994, the licensee reported that they had identified a condition outside the design basis of the plant. Specifically, the 75,000 gallon main fuel oil tank (MFOT) level had dropped to 6'-0", a level which is below the system design level of 6'-3" to ensure sufficient fuel oil pump suction. The MFOT normally supplies fuel oil to the 15,000 gallon emergency diesel generator (EDG) fuel storage tank (FST). However, in the event of a postulated loss of offsite power and a fire in the EDG FST, fuel oil supply to the EDGs would be lost. For that case, a bypass line is used to provide a gravity fuel oil supply from the MFOT directly to the EDG skid mounted fuel oil pumps. The FSAR (Section 9.5.4) states that the minimum level for the 75,000 gallon MFOT must be 8'-0" prior to initiating the bypass supply to insure adequate suction pressure at the skid mounted pumps.

The licensee reviewed related design documentation (SDD-OC-810A) and determined that the purpose of the 8'-0" level is to provide a sufficient amount of fuel oil to operate one of the two EDGs at maximum capacity for 24 hours. At the end of 24 hours, the MFOT level will be 6'-3," which is the lowest safe operating level for the EDG skid mounted transfer pump. The design document indicates that fuel delivery is required within the 24 hour period following initial start of operation in that mode to assure adequate EDG skid mounted pump suction.

During the equipment operator shift tours, the operators noticed that the MFOT was approaching 8'-0" at 8:00 p.m. on February 12, 1994, at which time the control room Group Shift Supervisor (GSS) ordered a fuel oil delivery. However, the GSS was informed that the delivery would be delayed due to adverse weather conditions. The GSS subsequently ordered an emergency fuel oil delivery in accordance with the vendor contract provisions. The fuel oil was received at 2:00 p.m. on February 13, 1994, a... the MFOT had reached a minimum level of 6'-0". Level was restored to greater than 8'-0".

The licensee reported this event as a condition beyond the design basis because the MFOT level dropped below the 6'-3" value. The licensee stated that the difference between 8'-0" and 6'-3" allows 24 hours for fuel delivery. In this case, however, the heating boiler was in service in support of various systems, consuming a relatively high rate of fuel oil due to the adverse weather conditions.

The inspector questioned whether any automatic, manual or administrative controls were in place to prevent concurrent operation of the heating boiler and EDG under the above postulated event. The licensee's review of this event determined that weaknesses were evident in procedures related to this issue. Specifically, 1) sufficient guidance was not provided to the GSS and operators regarding the level at which fuel oil should be ordered for the MFOT, and 2) there was no direction to reduce loads or shut down the heating boiler in the event that the assumed situation occurs. The inspector verified that following this event, the licensee promptly added specific guidance to the equipment operator tour sheets so that timely fuel oil orders could be made, and also providing additional margin to 8'-0". In addition, the licensee is evaluating other operating and abnormal procedures to determine whether additional enhancements or contingency actions would be appropriate. In addition, while investigating this issue, it was apparent that the FSAR did not accurately describe system design basis. As a result, the licensee stated that they would initiate an FSAR change to make it more consistent with the system design description.

The licensee's evaluation of this event determined that operation of the fuel oil transfer pumps at a MFOT of 6'-0" would not prevent an adequate fuel oil supply to the EDG. In addition, in the event of the inability to provide fuel oil to the EDGs, a station blackout transformer was available to provide power directly to the necessary electrical buses. Therefore, the safety significance of this event is minimal. The inspector concluded that the licensee's completed and proposed actions to resolve this event were appropriate.

2.0 MAINTENANCE (61726, 62702, 62703)

2.1 Maintenance Activities

The inspectors observed selected maintenance activities on 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 also noted that Quality Control personnel were monitoring the work activities.

The inspector observed portions of the following activities.

Job Order (JO)	Description
JO 51357	Replace GE/MAC containment spray to emergency service water delta pressure transmitters (DPT-IP05A, B, C, and D) with Rosemount Model 1152 delta pressure transmitters;
JO 51211	Containment spray system 1 heat exchanger drain line reroute installation;
JO 51889	"D" reactor recirculation motor generator brush/slip ring inspection;
JO 52654	"D" reactor recirculation motor generator fluid coupling sample.

The maintenance activities observed were effective with respect to meeting the safety objectives of the maintenance program.

2.2 Control of Troubleshooting Activities

The inspector reviewed the licensee's program for the control of troubleshooting activities. This inspection was performed in accordance with NRC Temporary Instruction No. 94-01. Two prior NRC inspections reviewed portions of the licensee's troubleshooting program and implementation (50-219/93-11 and 50-219/93-81).

Station procedure No. 2400-ADM-3660.01, "Conduct of Installed Instrument Troubleshooting, Calibration and Maintenance," provides the written instructions for performing troubleshooting at Oyster Creek. The procedure also delineates the worker responsibilities for troubleshooting activities. The troubleshooting procedure was developed by the maintenance organization, and is used primarily by instrument and control (I&C) technicians and electricians. The operators and system engineers occasionally perform, direct, or coordinate troubleshooting activities. There is no formal system currently in place to be used by either operators or system engineers to control troubleshooting (See NRC Report 50-219/93-11). However, in response to this previously identified concern, the licensee has initiated efforts to develop a troubleshooting work standard, which would apply to both operators and system engineers.

Troubleshooting at Oyster Creek for "Nuclear Safety Related" (NSR) and "Regulatory Required" (RR) items is officially documented by use of a Job Order (JO), as specified by procedure No. C000-WMS-1220.08. Maintenance planners, who develop the JO packages, determine whether the troubleshooting is to be performed in accordance with procedures or without procedures (within the "skill of the craft"). The licensee stated that nearly all of the planners (I&C, electrical, mechanical) have worked as technicians or supervisors before becoming planners. In addition, the planners receive the cyclic training provided to the technicians working in their area of responsibility. Therefore, the licensee felt that the planners are sufficiently qualified to make an appropriate determination whether planned work is within the skill of the craft or requires a procedure.

The JO has a section entitled "Work Sequence," in which the controls to accomplish the work and related instructions are provided. These instructions may include existing approved procedures or vendor manuals (in full or in part), engineering department direction, specific guidance developed by the planners, or it may specify the use of skill of the craft. The JO also provides sections to specify 1) reference documents, 2) prerequisites, and 3) precautions and limitations. A section is also provided to document the use of measuring and test equipment. The JO requires the signature of the control room Group Shift Supervisor (GSS), who is a senior reactor operator, to authorize the start of work for any JO. The GSS is responsible to identify any Technical Specification limitations or other limitations due to plant operations that may apply during the requested maintenance.

Procedure 2400-ADM-3660.01 defines troubleshooting as "diagnosing and locating malfunctions or breakdowns in equipment by means of systematic checking or analysis." The procedure requires the performance of a risk assessment for critical components or systems, as defined in Attachment 3 of the procedure. The inspector reviewed completed JOs and in-progress maintenance activities, and interviewed licensee personnel to verify implementation of the troubleshooting procedure. The inspector found that the licensee does not typically implement the troubleshooting requirements (e. g. risk assessment) when they suspect a particular component as the cause for a particular problem. In addition, for the case of an erratic instrument reading, the performance of an unscheduled surveillance to verify or calibrate the setpoints of an individual transmitter does not constitute troubleshooting. Rather, that activity is considered corrective maintenance.

The critical component list in Attachment 3 of the troubleshooting procedure includes systems such as emergency diesel generator, reactor protection, and core spray. These systems require a risk assessment to be performed prior to troubleshooting. An assigned risk level of high or very high require the implementation of additional work controls and approvals for the troubleshooting activity. However, the inspector determined that risk assessments are not required for systems such as reactor recirculation control system or the feedwater control system. Both systems can potentially result in operational transients (including a reactor scram) if problems occur during troubleshooting or if the activity is not properly controlled. For example, on March 7, 1994, while performing an unscheduled calibration for the "B" feedwater flow indicator, an activity that is normally performed with the reactor shutdown, an operational transient occurred (See Section 1.4 of this report for additional details of this event). That activity was performed using corrective maintenance JO 47790. No risk assessment was performed. NRC Inspection 50-219/93-81 also identified a concern in which the licensee inconsistently applied the procedural requirement to perform risk assessments.

During this inspection period, an additional operational transient occurred on March 3, 1994, when the "B" reactor recirculation pump inadvertently tripped (See Section 1.3 of this report). In that case, work performed to investigate the cause for the pump motor-generator trip was controlled as minor maintenance (MM), which can be used for systems classified as "Other" as opposed to NSR or RR. The MM process requires much less planning than maintenance accomplished under the JO process. In addition, there are no specific documentation requirements. As such, any data collected by maintenance personnel to determine the cause of the event following the transient could be discarded. For this event, however, the electrical supervisor involved with the maintenance activity documented the work performed and recorded the MM activity in the computerized data system (GMS2).

In general, corrective maintenance may be performed during the troubleshooting process. If, however, the cause and anticipated repairs are found to be outside of the original scope of the associated JO, then a new or revised JO is generated. With the exception of the above mentioned feedwater transient (which was not defined as troubleshooting by the licensee), the inspector did not identify any notable recent events occurring at Oyster Creek where troubleshooting was a causal factor.

The information obtained during this inspection activity will be reviewed by NRC Region I specialists to determine whether additional followup is warranted. The inspector will continue to monitor the effectiveness of licensee troubleshooting activities during routine resident inspections.

2.3 Industrial Safety Performance Concerns

During the power reduction for main steam isolation valve testing, on February 26, 1994, the inspector observed maintenance activities (Job Orders 51889 and 52654) associated with the "D" reactor recirculation pump motor generator (MG). The inspector concluded that the workers involved were knowledgeable regarding the tasks assigned and the assignments were properly executed. However, the inspector noted severed concerns regarding implementation of the licensee's industrial safety standards. Specific lly, some of the personnel were not wearing the required hearing protection, no hard hats were worn, and one worker was wearing inappropriate eye protection (sunglasses) inside the MG set room. In addition, the inspector observed the application of a clear cleaning solvent (from an unmarked container), and the individual was not wearing protective gloves. The inspector informed the Operations-Maintenance Director of the observed concerns, who subsequently implemented appropriate specific corrective actions. The inspector will continue to monitor licensee performance in this area to identify whether programmatic weaknesses are evident.

2.4 Surveillance Activities

The inspectors performed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspectors reviewed the following surveillance test procedures and observed portions of the associated testing activities:

Procedure No.	Test
609.4.001	Isolation Condenser Valve Operability and Inservice Test (IST);
619.3.011	Scram Discharge Instrument Volume (SDIV) Digital Level Calibration and Test, and SDIV Valve Exercise and IST;
625.04.002	Main Turbine Surveillances;
607.4.004	Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test.

The inspectors noted that a properly approved procedure was in use, approval was obtained and prerequisites satisfied prior to beginning the test, 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 test procedure.

2.5 Verification of Valve Restoration Steps

While observing the performance of surveillance test procedure 619.3.011, "SDIV Digital Level Calibration and Test, and SDIV Valve Exercise and IST," the inspector raised a concern regarding the licensee's practice of verifying action steps. During this test, two technicians were performing the procedure steps for components that are located within a radioactively contaminated area (CA). The technicians were wearing the proper protective clothing. A third worker was located outside of the CA, and was reading the procedure steps to the workers. Certain of the procedure action steps, particularly those steps that restore the safety related instruments to service, require a verification signoff. For those instances, the worker located outside the CA watched the individual inside manipulate components. He then initialled the verification signoffs. Although there were two technicians inside the area, each worked on different level switches.

The inspector expressed a concern that the verifier did not practice a physical verification of the action step. The licensee informed the inspector that the verification process implemented was in accordance with Oyster Creek standard practices for work inside CAs in order to keep exposure and contamination to a minimum. The inspector confirmed that precaution and limitation (step No. 4.9) of the procedure documented that practice. That step also stated that the test is normally done by two individuals (one inside the CA; one outside the CA).

The inspector concluded that the licensee's practice of not performing a physical verification of components represents the potential to leave a system improperly aligned. In addition, as for the case above, there were two individuals inside the contaminated area such that physical, independent verification could have been practiced. The inspector concluded, that when feasible, physical verification should be performed to minimize the likelihood of valving errors.

2.6 Programmatic Controls to Enter Technical Specifications During Surveillance Testing

In response to concerns identified in NRC Inspection 50-219/93-81 and a subsequent NRC Notice of Violation (letter dated February 24, 1994), the licensee implemented several actions related to entering Technical Specification (TS) Limiting Conditions for Operation (LCO) for surveillances which render components/systems inoperable. Previous to this time, the licensee did not routinely enter TS LCOs when surveillance testing rendered systems inoperable and therefore unable to perform its intended design function.

Prior to the associated NRC Enforcement Conference, conducted on January 25, 1994, the licensee identified 43 surveillance procedures which potentially render plant components or systems inoperable. By memorandum dated January 27, 1994, the Plant Operations Manager issued interim guidance to all licensed operators concerning entering LCOs for surveillance testing. The memorandum identifies 30 of the 43 specific surveillance tests which were subsequently reviewed, and listed the applicable TSs and the related required action to be taken (such as entering LCOs) during surveillance testing. The evaluation for the remaining surveillance tests was deferred as those tests are only performed with the reactor shutdown. The interim guidance is to remain in effect until permanent changes are incorporated into procedure No. 106, "Conduct of Operations."

The inspector reviewed the guidance provided in the memorandum, and found the actions to be appropriate. In addition, the inspector found control room operators to be properly implementing the guidance during surveillance testing. To date, no discrepancies were identified whose resolution necessitates immediate NRC action, such as enforcement discretion. The inspector concluded that the licensee's response to this concern is acceptable.

3.0 ENGINEERING (71707, 40500)

3.1 Pressure Isolation Valve and Containment Isolation Valve Review (Unresolved Item 50-219/94-03-02)

The inspector reviewed the licensee's requirements for monitoring and testing pressure isolation valves (PIV). PIVs are defined (See NRC Generic Letter 87-06) for each interface as any two valves in series within the reactor coolant pressure boundary which separate the high pressure reactor coolant system (RCS) from an attached low pressure system. The inspector performed this review in response to events at other nuclear power plants in which leakage past PIVs occurred. The inspector found during this review that the licensee properly tests the PIVs as required per Technical Specifications (TS), however, concerns were identified with the accuracy and completeness of both TS and FSAR containment isolation valve (CIV) tables.

The inspector reviewed two primary systems that interface with the RCS at Oyster Creek, the shutdown cooling system and the core spray (CS) system. Since the entire shutdown cooling system is fully rated to 1250 psig, and therefore does not contain PIVs, this review was limited to the CS system. TS 3.3.G requires the operability of the four PIVs (testable check valves) listed in TS Table 3.3.1 (two for each of the two CS systems). TS 4.3.G requires periodic leakage testing of the PIVs. The inspector determined that the PIV arrangement consists of two check valves (in parallel) for each of the two CS systems. There are two motor operated valves, also in parallel, upstream each set of check valves. These valves are called the parallel isolation valves and are normally closed.

The inspector questioned the licensee concerning the PIV arrangement and testing requirements. They stated that TS 3.3.G and 4.3.G were the result of an NRC Order, dated April 20, 1981. Although the parallel isolation valves are not PIVs, the licensee includes the parallel isolation valves in the Inservice Testing Program, and incorporates a leakage testing requirement to the procedure (No. 610.4.011) that periodically leak tests the check valve PIVs. That test determines gross leakage (less than, or greater than, 1 gpm) for the parallel isolation valves.

The inspector reviewed completed test data for the CS testable check valves. The data from 1989 to present indicates very low leakage rates. However, it appeared that several of the completed check valve leakage tests were conducted after valve maintenance (e. g. repack valves, repair of separated stem). Based on a review of the data base that contained the dates and general descriptions of the work performed, it was not clear whether as-found testing was accomplished (testing prior to maintenance). The licensee subsequently stated that as-found testing was not required for the check valves because they are not 10 CFR 50, Appendix J valves. They further stated that the CS check valves are not CIVs per TSs.

The inspector subsequently confirmed that the CS system testable check valves were not identified as CIVs in TS 3.5.3, Table 3.5.2. However, the inspector identified that both the CS testable check valve PIVs and the parallel isolation valves are identified in the FSAR (Table 6.2-12) as being CIVs. In addition, the FSAR table notes a required full closure time of 20 seconds for the parallel isolation valves. The FSAR table identifies many more valves as CIVs than TSs.

The licensee informed the inspector that they had previously recognized the noted CIV table discrepancies, and that a TS change request was being developed to resolve the TS Table 3.5.2 concerns. They stated that 1) there were some valves that were listed on Table 3.5.2 that should not be, and 2) there were CIVs missing from the table. They further stated that there are existing administrative controls in place (procedures) to ensure that the appropriate TS Action Requirements are applied for all necessary CIVs.

The inspector reviewed both the TS and FSAR CIV tables, and operations procedure No. 312.9, "Primary Containment Control." While procedure 312.9 contains a primary containment system valve lineup that appears to be comprehensive, the procedure does not clearly identify them as CIVs, and therefore applicable to the TS 3.5.3 requirements. The inspector concluded that the licensee must complete their review of CIV tables and provide consistent guidance to operators so that the appropriate controls are reflected for CIVs. Pending further review by the NRC regarding specific CIV compliance with TSs, and resolution of the inconsistencies related to the FSAR and TS CIV tables and other procedural guidance, this item is unresolved. **(UNR 50-219/94-03-02)**

3.2 Electromatic Relief Valve Torus Loading Review

NRC inspection report 50-219/93-27 discussed the preliminary information and evaluation of possible increased Mark I containment loading because of an incorrect Electromatic Relief Valve (EMRV) lift pressure used by a consultant during the Oyster Creek Plant Unique Analysis. Review of initial information by NRR (mechanical engineering) indicated that stress loading would not be increased significantly by the different EMRV lift pressure setpoint. The final evaluation was issued by the licensee on December 30, 1993. The final evaluation concluded that additional stress loading due to the incorrect lift pressure setpoint would be less than 1 percent. NRR (mechanical engineering) review of the final evaluation concluded that the report was detailed, comprehensive and accurate. Increased stress loading due to the incorrect lift pressure setpoint was of minor significance.

The inspectors concluded that corporate engineering had responded appropriately to the initial problem identification and had provided a comprehensive and detailed evaluation to the NRC.

3.3 120 Volt AC System Outside Design Basis Under Degraded Grid Voltage Conditions (UNR 50-219/93-21-03 Update)

On February 14, 1994, the licensee reported to the NRC that the 120 volt AC (VAC) system would be outside its design basis under degraded grid voltage conditions. The discovery was a result of licensee efforts to resolve a previously reported (September 9, 1993) condition of 4160 VAC bus second level undervoltage relay setting inadequacies. The inspectors concluded that the licensee actions to date are appropriate. Evaluations are being conducted on a continuing basis. The licensee has performed an evaluation from the 120 VAC level back to the 4160 VAC bus to determine the minimum voltage necessary on the 4160 VAC bus that will ensure operability of the 120 VAC equipment and instrumentation.

The licensee determined that a 4160 VAC bus voltage of 4100 VAC would ensure operability of instrumentation on the 120 VAC buses. To ensure that 4160 VAC does not drop below 4100 VAC, the licensee implemented the following actions:

- Obtain hourly voltage readings on start-up transformers to ensure voltage is 4100 VAC or greater.

- Keep 34.5 kV voltage regulators (input to 34.5/4.16 kV transformers) in operation to ensure greater than 4100 VAC.

- Keep 120 VAC power panels on rotary inverters as much as possible.

- Transfer to emergency diesel generators if voltage drops below 4100 VAC.

This information was communicated to both NRC Region 1 and NRR for review and evaluation. It was determined that licensee actions were appropriate for interim measures until the degraded grid voltage problem evaluation is fully addressed. This item will be carried under existing unresolved item No. 50-219/93-21-03.

4.0 PLANT SUPPORT (71707)

4.1 Radiological Controls

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 (RWPs) and survey status boards were current and accurate. The inspectors 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.

4.2 Security

During routine 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 isolation zones were free of obstructions. The inspectors examined vital area access points and verified that they were properly locked or guarded and that access control was in accordance with the Security Plan.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (40500, 90712, 90713)

5.1 Licensee Event Report (LER) and Periodic Report Review

NRC inspectors reviewed the following LER and verified appropriate reporting, timeliness, complete event description, cause identification, and complete information. In addition, the need for on site review was assessed.

Licensee Event Reports

- LER 94-01 describes the licensee's identification that the minimum recirculation line for each of the two core spray systems exceeded the design basis code allowable stress values. This event was discussed in NRC Inspection No. 50-219/93-29. This LER states that a supplemental report will be submitted around September 1994. Pending submittal of that report, this LER remains open.

Periodic Reports

- Monthly Operating Report for January, 1994.

The inspector concluded that the above reports were acceptable.

5.2 Review of Previously Opened Items

(Closed) Violation 50-219/92-05-01

Failure to evaluate the security program's potential impact on plant and personnel safety during the annual quality assurance (QA) audits. The inspector reviewed the 1992 QA audit during NRC inspection 50-219/93-26, conducted November 1-5, 1993, and found it to contain an appropriate evaluation of the security impact on safety. This item is closed.

(Closed) Unresolved Item 50-219/93-21-01

This item has been upgraded to a violation as detailed in Section 5.3.

(Open) Unresolved Item 50-219/93-21-03

While continuing an evaluation of this item (4160 volts AC second level undervoltage relay setpoints), the licensee identified a similar potential undervoltage condition of the 120 VAC buses during degraded grid voltage conditions. The new finding will be carried under the existing unresolved item until final resolution of the degraded grid voltage problem. This item is discussed in Section 3.3 of this report.

5.3 Temporary Strainers Installed in Plant Systems (Violation 50-219/94-03-03)

During routine plant tours, the inspector noted two tabs protruding from flanged connections on the core spray (CS) pump suction supply from the condensate storage tank (CST). The first tab was identified on February 9, 1994, on CS pump P-20-1A; the second, on March 2, 1994, on CS pump P-20-1B. The protruding tabs are thought to be temporary suction strainers left installed from initial construction and pre-operational testing periods, during the late 1960's. This was discussed with the system engineer and the Operations and Maintenance Director, as well as the Site Licensing Manager. Strainers are not shown on plant drawings and the tabs do not necessarily identify them as strainers; however, a similar tab was identified in the reactor building closed cooling water (RBCCW) system during NRC inspection 50-219/93-21 (August - September 1993). A flanged section of the suction of RBCCW pump No. 1-2 was recently taken apart, and the temporary suction strainer was removed. RBCCW flow did not appear to be restricted by the strainer, as normal flow was observed during normal system operation and pump testing while the strainer was installed.

Pre-operational test procedures indicate that the CS system was successfully flow tested using the CST as a source of water in March 1969. Since that time, flow testing from the CST has not been performed because the return test path is to the torus, which would result in unacceptably high torus water levels. The flow path from the CST is not required to be operable during power operation per Technical Specifications; however, it is required to allow the CS system to be removed from service during shutdown periods.

Since the identification of the two possible CS system strainers, the licensee has reissued licensing action item (LAI) 85264.02 to physically inspect all piping systems for temporary strainers, which was initially issued to address NRC Information Notice 85-96, Temporary Strainers Left Installed in Pump Suction Piping. A work request (WR 763604) has been issued to inspect the CS system to identify and remove any strainers.

As noted in NRC inspection 50-219/93-21, NRC Information Notice 85-96 was closed by the licensee based on an administrative review. No physical inspection of systems was performed. That NRC inspection identified the RBCCW system strainer. It appeared that the licensee had identified the RBCCW system strainer tab in 1990 but had not taken prompt action to verify it to be a stainer or to remove it. Subsequently, during this inspection period, the NRC identified two additional possible strainers installed in the safety related CS system. Licensee action to identify and remove temporary suction strainers has not been timely. Failure to identify and implement effective corrective actions regarding strainers installed in plant systems is a violation of 10 CFR 50, Appendix B (Corrective Action) requirements. **(Violation 50-219/94-03-03)**

6.0 EXIT INTERVIEWS/MEETINGS (30702, 94703)

6.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on March 18, 1994. 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.

The inspection consisted of normal, backshift and deep backshift inspection; 53.5 of the direct inspection hours were performed during backshift periods, and 13 of the hours were deep backshift hours.

6.2 Attendance at Exit Meetings

The resident inspectors attended exit meetings for other inspections conducted as follows:

Date	Lead Inspector	Subject	Report No.
February 4, 1994	Jang	Dose Assessment	50-219/94-04
March 4, 1994	Eckert	Exposure Controls	50-219/94-05

At these meetings, the lead inspector discussed preliminary findings with senior GPUN management.

6.3 SALP Management Meeting

On March 7, 1994, NRC Region I senior management met with GPUN senior management to discuss the most recent Systematic Assessment of Licensee Performance (SALP) report, dated January 26, 1994. The meeting was held at the GPUN Energy Spectrum, and was open to the public. The NRC slides used are attached.

ATTACHMENT

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE (SALP)

OYSTER CREEK NUCLEAR GENERATING STATION

ASSESSMENT PERIOD: JULY 19, 1992 - DECEMBER 11, 1993

MANAGEMENT MEETING: MARCH 7, 1994

Agenda

SALP Management Meeting
March 7, 1994
1:00 PM

NRC INTRODUCTORY REMARKS:

W. F. Kane, Deputy Regional Administrator

GPUN INTRODUCTORY REMARKS:

P. R. Clark, President & CEO

NRC SALP PROCESS:

W. F. Kane

NRC SALP REPORT PRESENTATION:

J. F. Rogge, Chief, Reactor Projects Section-4B

DISCUSSION AND GPUN COMMENTS:

GPUN CLOSING REMARKS: P. R. Clark

NRC CLOSING REMARKS: W. F. Kane

PERFORMANCE ANALYSIS AREAS FOR OPERATING REACTORS

A. PLANT OPERATIONS

B. ENGINEERING

C. MAINTENANCE

D. PLANT SUPPORT

PERFORMANCE CATEGORY RATINGS

CATEGORY 1 - SUPERIOR PERFORMANCE

CATEGORY 2 - GOOD PERFORMANCE

CATEGORY 3 - ACCEPTABLE PERFORMANCE

Performance Analysis Summary
Previous SALP Period

Functional Area	Rating, Period Ending 07/18/92
1. Plant Operations	2
2. Radiological Controls	2, Improving
3. Maintenance/Surveillance	2
4. Emergency Preparedness	1
5. Security	2
6. Engineering and Technical Support	2
7. Safety Assessment/Quality Verification	2

PLANT OPERATIONS

- Excellent Operator Response To Plant Challenges And Planned Activities
- Effective Control Of Outage Work
- Lack Of Written Plan And Risk Assessment For Troubleshooting
- Excellent Licensed And Non-Licensed Operator Training Programs
- EOP Upgrades
- Good Questioning Attitude
- Weakness In Temporary Procedure Change Process
- Inconsistent Or Inappropriate Application Of TS Requirements
    - 4.16 Kv Bus Undervoltage Relays
    - APRM Operability Determination

Rating: Category 2

ENGINEERING

- Well Planned Design Modifications
  - Drywell Modification
  - Station Blackout
  - Containment Spray Auto Logic
  - Isolation Condenser Piping
  - Service Water Piping
- Onsite System Engineering Organization
- Excellent Engineering Analyses
- Good Licensing Submittals
- Strong Safety Ethic
- Good Support Of Maintenance And Operations
- Incomplete Safety Evaluations And Responses To Industry Notices
- Timeliness Of Inputs For Operability/Reportability Issues

Rating: Category 1

MAINTENANCE

- Strong Safety Perspective
- Management Oversight
- Good Support Of Management Initiatives Related To Plant Risk
- Shutdown Risk Management Program A Strength
- Improvement In Preventive Maintenance Program
- Good Corrective Maintenance
- Weaknesses In Surveillance Procedures
  - Core Spray
  - APRM High-Level Clamping
  - Unintentional Rapid Depressurization
- Programmatic Weaknesses In Surveillance Testing

Rating: Category 2

PLANT SUPPORT

- Superior Performance In EP Program
  - EP Exercise Performance
  - Relationships With Offsite Organizations
- Superior Housekeeping And Fire Protection Programs
- Adequate Security Program
  - Response To External Threats
  - Improved Maintenance Support
- Well-Staffed Radiological Controls Program
- ALARA Preparation Coordination And Control Of The 14R Outage
- Good ALARA Program
- Poor Mechanism For Initiating ALARA Reviews
  - Inadequate Instructions
  - Failure To Review Work
- Weaknesses In RAD Control Program
  - Access Controls
  - Improper HRA Barrier Restoration And Setup
  - Poor Adherence To HRA Controls

Rating: Category 2

OVERALL CONCLUSION

- IMPROVED PERFORMANCE
- EXCELLENT OVERALL SAFETY PERSPECTIVE
- STRONG MANAGEMENT OVERSIGHT
- CONTINUED MANAGEMENT ATTENTION NEEDED TO TRACK AND RESPOND TO INDUSTRY EXPERIENCE
- WEAKNESS IN TEMPORARY PROCEDURE CHANGE PROCESS
- OPERABILITY/REPORTABILITY DETERMINATIONS
- GREATER ADMINISTRATIVE CONTROLS NEEDED OVER TROUBLESHOOTING
- MAINTAIN PROGRESS IN PREVENTIVE MAINTENANCE PROGRAM
- PROGRAMMATIC WEAKNESSES IN THE SURVEILLANCE PROGRAM
- IMPROVED PERFORMANCE IN ENGINEERING
- GOOD PLANT SUPPORT
- IMPLEMENTATION OF THE EFFLUENT AND ENVIRONMENTAL MONITORING PROGRAM NEEDS IMPROVEMENT