U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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License No.	DPR-16
Licensee:	GPU Nuclear Corporation 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	July 31, 1995 - September 10, 1995
Inspectors:	Larry Briggs, Senior Resident Inspector Stephen Pindale, Resident Inspector Al Lohmeier, Senior Reactor Engineer, Region I

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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 provides the inspection findings and conclusions.

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 95-15

Plant Operations

During the inspection period, the NRC staff noted that the plant was operated safely. Several performance deficiencies were caused by inattention to detail during routine activities. Due to human error, a licensed operator mispositioned a control rod while moving it following testing; the licensee's response and followup were very good. The remaining operable emergency service water system was made inoperable for surveillance testing for about one hour during a period of time when the redundant system was also (unknowingly) inoperable; this was due to an incomplete documentation and review of a completed surveillance procedure. In addition, ineffective communications and inattention to detail resulted in an unplanned, but monitored, radioactive liquid discharge while flushing the service water radiation monitor.

Maintenance

The licensee effectively performed preventive and corrective maintenance and surveillance activities on a system outage basis to minimize system out of service times. The maintenance backlog was found to be well managed and prioritized. Ineffective verbal and written communications resulted in cutting a cracked instrument pipe in the core spray system at the crack; as a result, the failed section could not be properly analyzed to determine the root cause of failure. Communications between operations and engineering personnel were weak following the performance of an annual fire pump surveillance test; essential details of problems experienced during the test were not discussed.

Engineering

Engineering provided good support in investigating abnormal performance of a reactor building-to-torus differential pressure switch. A system engineer's independent review of a vendor's information letter identified that Oyster Creek was vulnerable to the deficiency described in the letter despite a prior preliminary conclusion to the contrary. However, an isolated instance of poor turnover in the related vendor program several years ago caused a significant delay (about 10 years) in evaluating the document. Once identified as a concern, appropriate corrective actions were taken.

Plant Support

Routine observation of station personnel by the inspectors indicates that radiological controls and security program requirements are being effectively implemented by the licensee and followed by station personnel.

Safety Assessment/Quality Verification

The licensee had known about a discrepancy related to a technical specification item that did not reflect actual plant configuration. For many years, however, no action was taken to correct the discrepancy or to provide sufficient compensatory interim operator guidance for instances when the associated core spray system differential pressure instruments become inoperable; this demonstrated weakness in maintaining the licensing basis. GPUN effectively completed an extensive effort to address prior problems with monitoring, recording, and analyzing component fatigue usage factors.

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DETAILS

1.0 PLANT OPERATIONS (71707,93702)

1.1 Operations Summary

The plant operated at full power during this period except for power reductions necessary to prevent exceeding the New Jersey environmental discharge permit temperature limit, to perform the quarterly main steam isolation valve surveillance (August 12), and to complete repairs to the "A" (August 25-27) and "B" (August 11-13) reactor feedwater pump seals.

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
- access control points
- fire pump building
- intake area
- reactor building
- turbine building
- vital switchgear rooms
- transformer yard

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

1.3 Mispositioned Control Rod Following Scram Time Testing

On August 12, 1995, following the completion of control rod scram time testing (for four rods), a control room operator inadvertently withdrew control rod 42-19 to notch 40, two notches beyond its intended position of notch 36. By definition per station procedures, the control rod was "mispositioned." The reactor was operating at 70% to support "B" feedwater pump maintenance. The onshift reactivity manager notified the reactor engineer that a control rod was mispositioned. The operator then inserted the control rod to notch 36 with the core engineer's concurrence and the onshift reactivity manager's direction. The onshift personnel followed up by notifying the manager of plant operations and submitting a deviation report.

The licensee subsequently completed a formal critique of this incident. The root cause was determined to be human error. The critique concluded that all administrative controls were in place to prevent this event. The associated maneuver request sheet clearly and accurately directed rod 42-19 to be withdrawn from 00 to 36. The activity was sufficiently supervised by the onshift reactivity manager, a licensed senior reactor operator. And, the operator performing the activity verbalized his intended actions (as per the maneuver request sheet). However, the operator continued to withdraw the control rod past notch 34 until the onshift reactivity manager voiced his concern that the operator was going beyond notch 36. The operator immediately released the controls, and the control rod settled at 40. Apparently, the operator's lack of concentration allowed him to be distracted and lose his train of thought.

The inspector reviewed the critique report, and concluded that this event was thoroughly reviewed and documented. Actions taken by the licensee included discussing this event with the shift crew involved to reinforce management's self-checking expectations. The licensee is also evaluating a practice of performing large control rod withdrawals with the addition of intermediate stop points to assist self-checking techniques. The inspector concluded that the licensee's followup and evaluation of this event were very good.

The licensee immediately identified, properly assessed and corrected the condition. This event represents a violation of Technical Specification 6.8.1, which requires that written procedures shall be established, implemented, and maintained. However, this event was of minor safety significance and is being treated as a non-cited violation, consistent with Section IV of the NRC Enforcement Policy, 60 FR 34381, June 30, 1995.

1.4 Containment Spray/Emergency Service Water Inoperability

On July 31, 1995, the keep-fill check valve, V-3-133, stuck open while performing an operability and inservice test of containment spray/emergency service water (ESW) system 1 and required mechanical agitation to close it. The test results were reviewed by the group shift supervisor (GSS), and the system was determined to be operable based on system flow meeting the required value. No deficiencies were indicated on the surveillance procedure cover sheet. A notation located within the body of the surveillance procedure that V-3-133 had to be mechanically agitated was overlooked. The manager of plant operations (MPO) reviewed the surveillance test results on August 1, 1995, and questioned the operability of the system based on possible flow bypass if the check valve had stuck open. The MPO directed the GSS to initiate a deviation report to have engineering evaluate the amount of flow that would be bypassed and determine if the system would meet acceptable flow standards. The sticking check valve was discussed during the morning meeting (August 1) and engineering was tasked with calculating the bypass flow and performing an engineering evaluation of system operability. It was generally assumed that the system was operable based on the amount of ESW flow above the minimum acceptable value.

On August 2, 1995, the operability of containment spray/ESW system 1 was not discussed at the morning meeting and later in the day, a surveillance test was performed on containment spray/emergency service water system 2 that made it inoperable for a period of 1 hour and 10 minutes. Later that day, it was determined that the flow bypassed through the sticking check valve in system 1 would have lowered the ESW flow below the 3100 gpm acceptance criteria by 140 gpm. The licensee declared the No. 1 ESW system inoperable retroactive to the July 31 surveillance test. With system 1 inoperable due the sticking check valve and system 2 inoperable during surveillance test (1 hour and 10 minutes), the licensee had unknowingly entered Technical Specification (TS) 3.4.C.7, which requires placing the unit in a cold shutdown condition when both ESW systems are inoperable. The TS does not specify a time to cold shutdown; however, the licensee normally applies the 30 hours specified in TS 3.0.A ("motherhood") as the time required to accomplish a controlled shutdown. Per procedural guidance, the 30 hour TS 3.0.A shutdown must be started within one hour. In this case, a shutdown was not initiated because the licensee was unaware that TS 3.4.C.7 had been entered until after the condition requiring entry no longer existed. The inspector discussed the licensee's practice of treating TS required shutdown as a TS 3.0.A entry even when TS 3.0.A is not actually entered. The licensee agreed that further guidance was needed for the operations staff to clarify management's expectations for TS required shutdowns that are not the result of TS 3.0.A entries.

The check valves in both systems were replaced. The root cause for the sticking check valve was related to valve design/application. The licensee had previously recognized that flow through the check valve was high, which made the valves vulnerable to damage. In response to this concern, the licensee implemented a design change to reduce the keep-fill system flow rate by adding a throttle valve. However, the existing keep-fill check valves had previously been inservice under the higher flow conditions. The licensee stated that the check valve that was sticking experienced some internal valve damage due to the high flow conditions. They plan to inspect the new check valves in the near future to confirm the effectiveness of the reduced keep-fill system flow reduction modification on check valve performance.

The licensee performed a critique of this event and determined the root cause for not properly evaluating operability was the result of not understanding that a stuck open check valve could pass enough bypass flow to make the affected ESW system inoperable; and that the operability concern (urgency) was not clearly communicated to engineering, resulting in a delay of the bypass flow calculation.

The inspector determined that the licensee had conducted an acceptable critique of the event and took good corrective action when the system was determined to be inoperable; however, better attention to detail and a more questioning attitude by either the GSS or the group operating supervisor during the review of the surveillance test results would have identified the sticking check valve and resulted in corrective actions being taken on system 1 prior to performing surveillance on system 2. Although the sticking check valve was not identified as a deficiency on the surveillance procedure cover sheet, it was noted in the surveillance procedure and should have been questioned during the completed test review.

1.5 Unplanned Radioactive Discharge

On July 28, 1995, while flushing the service water radiation monitor (SWRM), an unplanned, monitored, radioactive liquid release to the discharge canal occurred. The SWRM is flushed weekly to minimize biofouling and to reduce sediment buildup. Normally, the chemistry department samples the demineralized water (DW) system prior to flushing; and if any activity above minimum detectable activity (MDA) is detected, the DW line is flushed by the chemistry department for several minutes (about 30 or 40 gallons) to get a clean sample. A flush of the DW line was not performed by chemistry on this occasion. The results of the sample were documented and delivered to the control room without verbal discussion of the results between chemistry and control room personnel. On the following shift, the GSS directed flushing of the SWRM. During the flush, the equipment operator noted an increase in count rate and contacted the chemistry department. The chemistry department informed the equipment operator that Cesium-137 levels were above MDA at 1.47 E-7 uCi/ml. The flushing was secured. The licensee used a conservative value of 400 gallons discharged, although it normally takes 40 gallons or less to flush the line to obtain a sample less than MDA.

The licensee performed a critique of this event and determined several root causes. Some of the causes were related to the routine repetitiveness of the task that resulted in lack of attention to the details of the chemistry results, lack of discussion of the results with the chemistry technician, and operations expectation of "flushing until clean" by the chemistry department. Another root cause was the fact that the DW system, which has always been free of contamination, was contaminated during the 15R outage and now requires a chemistry sample to verify activity less than MDA prior to use. The licensee proposed several actions to prevent recurrence of this and similar events including a long term action to develop a plan to resolve the contamination problem in the DW system such that sampling would not be required.

The inspector determined that the safety significance of this event was very low. Samples were taken before and after the discharge. The licensee took prompt action when it was discovered that the DW system activity was above MDA and the assumptions concerning the volume of contaminated water discharged were very conservative. The inspector concluded that better attention to detail concerning repetitive tasks would have prevented this event, as well as the event described in Paragraph 1.4 above. Also, the inspector noted that this discharge of radioactive liquid, although minor, was the first liquid effluent release made by the licensee in several years.

2.0 MAINTENANCE (62703,61726)

2.1 Maintenance Activities

The inspectors observed selected maintenance activities on both safety-related and non-safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards.

The inspector observed portions of the following activities.

Job Order (JO)	Description
JO 63194	Reactor Building 100 Ton Crane Tearout by American Crane
JO 63507	"A" Feedwater Pump Seal Replacement

JO 64013	Repair Instrument Root Valve Piping Near Core Spray System 2 Valve V-20-159
JO 60827	Reactor Building 100 Ton Crane Upgrade by American Crane
JO 500004	Replace Core Spray System 2 Discharge Pressure Switch RV-29D

The inspectors concluded that the above activities had been approved for performance and generally were conducted in accordance with approved job orders and applicable technical manuals (See Section 5.1.3 of this report for details related to JO 64013 performance problems). Personnel performing the activities were knowledgeable of the activities being performed and were observing appropriate safety precautions and radiological practices.

2.2 Maintenance Backlog

The inspector conducted a review of the licensee's maintenance backlog. The backlog was broken down into three areas for safety significance; nuclear safety related (NSR), regulatory required (RR), and "other." All open job orders (JO) related to a system, regardless of the affect or impact on system operability, are listed with that system. Items scheduled for the next outage were also included in the listing requested. The NSR systems had a total of 111 open items and the RR systems had a total of 148 items. The "other" listing which does not contain any items related to plant safety contained 317 outstanding items. The total non-outage open items at the close of this report period was 401. The inspector reviewed all three lists to verify that none of the open items would pose a negative affect on the safe operation of the plant. Because the one-line open item descriptions did not contain full details, the inspector requested additional information on 5 of the 111 open NSR items and one of the 148 open RR items. Based on discussions with the licensee and review of the more detailed description contained on the actual job order, the inspector's questions were satisfactorily answered; none of the job orders appeared to impact on system operability or safety. High priority (priority 1 and immediate maintenance) maintenance items are promptly planned, scheduled and performed. The assigned priorities, per procedure 105, "Control of Maintenance," are approved by the director of operations or the director of operations and maintenance.

The inspector determined that the licensee routinely performs maintenance (corrective and preventive) and surveillance activities on a system outage basis to minimize system out-of-service times. The scheduling of corrective and preventive maintenance is well controlled and managed with activities normally prioritized and scheduled well in advance. The non-outage corrective maintenance backlog has been worked down from a high of about 540 items to about 401 items since coming out of the 15R refueling outage.

2.3 Surveillance Activities

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

The following surveillance tests were reviewed with portions witnessed by the inspector:

Procedure No.	Test
636.4.003	Diesel Generator Load Test
607.4.004	Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test
617.4.001	Control Rod Drive Pump Operability Test
610.3.001	Core Spray Pump Failure Pressure Switches Surveillance Calibration
645.6.012	Fire Pump Functional Test

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.

2.4 Fire Pump Surveillance Test

On August 18, 1995, the inspector observed the performance of annual surveillance test 645.6.012, "Fire Pump Functional Test." The inspector determined that the test procedure incorporated the acceptance criteria specified in station procedure 101.2, "Fire Protection Program."

The annual test demonstrated operability of the fire system, however, some deficiencies occurred. The hardware deficiencies were documented by deviation reports and were related to discharge check valve leakage and discharge pressure gauge fluctuation. In addition, during the test, the No. 1 diesel-driven fire pump automatically started unexpectedly after the equipment operator placed the local mode switch to automatic. The operator then placed the mode switch to off, and the No. 1 diesel-driven fire pump stopped. However, No. 2 diesel-driven fire pump automatically started. It subsequently shut down automatically after a preset 15 minute logic time delay had expired.

The operations department submitted a deviation report for a procedure deficiency that was related to the above unexpected diesel-driven fire pump starts. However, the report only referenced that a procedure deficiency existed that could potentially render both diesel-driven fire pumps inoperable simultaneously for a short time period. It did not discuss the actual unexpected response.

About one week following the surveillance test, the inspector met with the fire protection system engineer that was assigned responsibility for the deviation report. The system engineer was not aware of the actual problems as they occurred during the test. The inspector discussed with the system engineer other system/procedure items observed during the test. The completed surveillance test procedure was still being reviewed by other station personnel at that time, and the system engineer had not seen the completed test procedure.

The surveillance procedure was completed satisfactorily, and fire system operability was demonstrated. Although completed surveillance procedures that demonstrate operability are not routinely reviewed by system engineers, the fire protection system engineer plans to conduct a thorough review of the completed procedure due to the concerns discussed above. He also plans to discuss the testing problem with operations and revise the test procedure, as appropriate.

The inspector concluded that communications between operations and engineering personnel were weak in that essential test problem details were not being discussed. The hardware problems were generally well documented and dispositioned. The deviation reports related to the fire system deficiencies were assigned an appropriate priority level for resolution.

3.0 ENGINEERING (71707, 37551)

3.1 Status of Individual Spent Fuel Storage Installation (ISFSI)

The inspector toured the ISFSI. The grounding system (installation in progress last report period) was complete and the trench was filled in. About 90 percent of the electrical cables and 60 percent of the security related cables have been pulled through their conduits. Terminations of cables at the storage facility had just started. Crane modifications were in progress, with an estimated completion date of mid-October. These modifications were reviewed as part of the maintenance verification (Section 2.1). Discussions with the onsite project manager indicate that there may also be some delay in the delivery dates of the concrete storage vaults. The total delay in the projected schedule is currently expected not to exceed one month.

On August 30, 1995, the Lacey Township Board of Adjustment, after several hearings, approved the sitting and operation of the proposed ISFSI at the Oyster Creek facility.

3.2 Mechanical Binding of Reactor Building-to-Torus Differential Pressure Switches (Open, IFI 50-219/95-15-01)

On August 22, 1995, the licensee identified that a reactor building-to-torus differential pressure switch (DPS-66B) experienced mechanical binding when differential pressure was applied during quarterly surveillance testing. The switch responded similarly during the prior test in May 1995. At that time, the switch was replaced with a new one and satisfactorily retested. On both occasions, a differential pressure of between 13 and 17 inches (water) was applied before the indicator moved from its downscale position. The licensee conducted a detailed review of the switch performance, and conducted accelerated testing. A preliminary contributing cause for the unexpected switch performance appears to be a manufacturing or design defect; however, further evaluation is necessary to conclude the licensee's root cause determination.

Following the August 22 surveillance test, the switch setpoint was verified to be within the required tolerance. The redundant sensor, DPS-66A, was tested with no abnormalities (only one of the two switches is required to actuate the two reactor building-to-torus vacuum breakers). The licensee then conducted additional testing to DPS-66B by alternatively applying pressure and vacuum to the sensor; the switch responded normally each time (at least six tests conducted). Although the licensee did not know the root cause of the binding, they recognized that the switch was in a reverse-pressurized state (about 1 - 2 psig) for three months prior to the last two surveillance tests. They concluded that the failure mode was time-dependent, and that it would be prudent to test the switch more frequently until the root cause could be determined. An engineering evaluation (276-95) was completed to document the licensee's actions and to conditionally justify operability of DPS-66B. For the remainder of the inspection period, DPS-66A and DPS-66B were satisfactorily tested on a four-day interval.

The two switches are manufactured by ITT Barton (model 581A). They were initially installed during the 15R refueling outage (Fall/Winter 1994), replacing the existing problematic switches, produced by another manufacturer. The licensee expects ITT Barton to be onsite September 17, 1995, to assist in identifying the root cause of the problem. The switch removed in May 1995 was previously returned to the ITT Barton for testing, however, no problems were identified.

The inspector reviewed the licensee's response and followup activities associated with this event, and concluded that their actions were appropriate. Resolution of this issue, including root cause, corrective actions, and possible generic implications, will be tracked as **Inspector Followup Item 50-219/95-15-01.**

3.3 Turbine Trip Reactor Scram Bypass Setpoint Adjusted Nonconservatively (Open, URI 50-219/95-15-02)

On August 25, 1995, the licensee reported that the bypass setpoint for the anticipatory reactor scram due to a main turbine trip was adjusted to a nonconservative value. They concluded that Oyster Creek had operated for an extended time period (several years) outside the Technical Specification (TS) limitation associated with this value. The licensee identified this during a review of General Electric Service Information Letter (SIL) 423, "Erroneous Scram Bypass Setpoint," and reported the deficiency to the NRC per the reporting requirements of 10CFR50.72.

The purpose of the anticipatory reactor scram is to mitigate the ensuing reactor pressurization transient following a turbine trip during power operations. However, at low power levels, the margins to fuel thermal-hydraulic limits and to reactor coolant primary boundary pressure limits are large, and the immediate scram is not necessary. Therefore, the power dependent, low power bypass of this scram is included in the plant design. At

Oyster Creek, this bypass is controlled by the main turbine third stage extraction steam pressure; it is designed to bypass the automatic reactor scram due to a turbine trip when third stage pressure drops below the setpoint.

The SIL discussed the scram bypass setpoint as being a function of rated reactor power. However, some plants used rated turbine power as a basis for the setpoint. This was the case for Oyster Creek, as the third stage extraction steam is an indicator of turbine power. However, this item was not a concern for Oyster Creek because both the reactor and turbine are rated identically, at 1930 MW.

The SIL also recommended that licensees review other factors that can impact the turbine power parameter (turbine pressure), such as operation with either 1) feedwater heaters out of service or 2) turbine bypass valves open. During the August 12, 1995 downpower, the licensee collected data and recorded the as-found bypass setpoint. Using the most restrictive assumptions (feedwater heaters isolated), the as-found scram bypass setpoint was equivalent to about 50% rated reactor power, which is nonconservative. The capability of the turbine bypass system is 40%. If a turbine trip were to occur between 40% and 50% power (with the feedwater heaters isolated), the reactor would likely scram due to high neutron flux or high reactor pressure since the anticipatory reactor scram would be bypassed. As an interim action, the bypass setpoints were evaluated and changed, and are currently set using conservative assumptions. The current setpoints are consistent with the design basis for the anticipatory scram.

During a review of the TSs, an inconsistency regarding the scram bypass setpoint was identified. The basis section of TS 3.1, "Protective Instrumentation," states that 40% of rated power has been chosen as the scram bypass setpoint. However, TS 3.1.A (Turbine Trip Reactor Scram), Note j, states that the scram is not required below 40% of turbine rated steam flow. The licensee is evaluating the applicable TS sections for a future revision.

At the end of this inspection, the licensee was evaluating the safety significance of the absence of the anticipatory reactor scram for the situation described above (scram between 40% and 50% power). Pending completion of the licensee's evaluation, this is an unresolved item. (URI 50-219/95-15-02)

The inspector reviewed the timeliness and adequacy of the licensee's evaluation of SIL 423. The SIL was issued on May 31, 1985, however a "potential" deviation report was not submitted until June 29, 1995. The licensee reviewed the history of this particular SIL as well as the associated vendor program to determine the cause of the delay in identifying this problem. The initial delay was caused by inadequate turnover of the GE SIL program responsibility; and then, a lack of accountability and followup resulted in delaying the assignment of the specific review task.

The GE SIL program responsibility was initially turned over in November 1985. At that time, SIL 423 was identified as needing to be dispositioned. Program responsibility was again turned over to vendor document control between 1987 and 1988. At that time, 19 SILs were identified as being open, however, SIL 423 was not one of the open SILs. In the 1990-1991 time period, vendor document control identified that some additional SILs were still open. After a complete SIL review, vendor document control identified 35 GE SILs that were still open with no response on record, including SIL 423. A complete package of the 35 SILs was sent to engineering for evaluation on November 10, 1992. While engineering closed 34 of the 35, the SIL review memorandum associated with SIL 423 stated only that it applied to Oyster Creek and that a specific action item should be assigned to evaluate it. The entire package was returned to vendor document control around March 1994, when it was realized that an action item was not assigned to evaluate SIL 423.

Subsequently, an October 18, 1994, memorandum documented the SIL 423 evaluation. However, it stated that there were no erroneous or non-conservative settings. A station engineer subsequently identified the potential concerns described above during his independent review of the October 1994 SIL response.

In summary, an unresolved item was opened to track the licensee's safety assessment of this event. The inspector concluded that although the status of SIL 423 and other SILs was poorly controlled and the initial evaluation of SIL 423 was inadequate, the licensee implemented proper corrective actions. The inspector concluded that a programmatic problem does not presently exist because the licensee's current program accounts for all GE SILs.

4.0 PLANT SUPPORT (71707, 71750)

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. They observed activities in the RCA and verified that personnel were complying with the requirements of applicable RWPs, and that workers were aware of the radiological conditions in the area.

4.2 Security

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

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707, 90712, 92903)

5.1 Core Spray System Pressure Switch Problems

5.1.1 Introduction

During this inspection, there were two equipment problems related to pressure switches in the core spray system. The first occurred on August 22, 1995, which was a ruptured diaphragm in pressure switch RV-29D (associated with the main pumps in core spray system 2). The second, on August 24, 1995, was a crack in a 3/4 inch pipe that could have adversely affected pressure switch RV-40B, also in core spray system 2.

The core spray system is comprised of two subsystems (1 and 2). Each subsystem contains redundant active components. There are two parallel main pumps and two parallel booster pumps for each subsystem. Upon a system initiation signal, the predetermined "priority" main pump starts in each subsystem. The discharge from the two main pumps join in a common length of pipe before splitting again for the two booster pumps. In the common main pump discharge pipe for system 1, pressure switches RV-29A and RV-29C start the associated backup main pump if sufficient discharge pressure is not developed within 10 seconds of the initiation signal. RV-29B and RV-29D provide the identical function in system 2.

In the common piping downstream of the core spray booster pumps, each subsystem contains two RV-40 differential pressure switches (RV-40A and RV-40C for system 1; RV-40B and RV-40D for system 2). If the priority booster pump does not achieve a 50 psig differential pressure within five seconds of the initiation signal, then the associated backup booster pump automatically starts. The RV-40 switches also provide input to the automatic depressurization system (ADS) initiation logic to ensure that a booster pump is operating prior to actuating ADS.

5.1.2 Ruptured Diaphragm in Pressure Switch RV-29D

On August 22, 1995, the licensee intentionally made a portion of the ADS initiation logic inoperable on two occasions to perform maintenance on failed pressure switch RV-29D in core spray system 2. A wire for the failed pressure switch and a wire for a high drywell pressure input to ADS were terminated at a common connection. The associated TS requirement for the ADS logic input (TS 3.1.A, Table 3.1, Item G.1, note "pp") allows for one channel in each of the two trip systems to be inoperable provided it is placed in a simulated trip condition within 24 hours or implement note "h." Note "h," however, appeared to be inconsistent with the above in that it stated one channel in each trip system can be inoperable if placed in the tripped condition (no time allotment) and the reactor is to be shutdown if repairs are not completed within 72 hours.

The licensee did not install an electrical jumper to trip the ADS drywell pressure channel due to physical limitations and the associated risk to adjacent connections. Therefore, they conservatively entered the shutdown portion of note "h" for the two short time periods during which the cables were disconnected; two minutes to de-energize the pressure switch, and about twelve minutes to re-energize the pressure switch. They reported their being in a shutdown TS to the NRC per the reporting requirements of 10CFR50.72. Due to the very short duration of the TS entries, an actual power reduction was not initiated.

The inspector reviewed the August 22 maintenance activity and concluded that it was properly planned, executed and supervised. The licensee delayed the maintenance so that the potential impact to ADS could be thoroughly evaluated. The switch was initially found to be inoperable one day earlier on August 21 during surveillance testing. At that time, the "D" core spray main and booster pumps were declared inoperable and the associated 7-day Action requirement of TS 3.4.A.3 was entered. After RV-29D was replaced and satisfactorily retested, core spray system 2 was declared operable and returned to service at about 3:00 p.m. on August 22.

At the end of the inspection, the licensee had not yet determined the root cause of the ruptured diaphragm. They plan to disassemble the switch in the instrument shop to inspect the diaphragm to determine the failure mode. The switch had been installed since 1985, and has an 18.6 - year qualified inservice life. The inspector confirmed that there was no adverse equipment performance history for the RV29 pressure switches. The licensee stated that they had previously recognized the discrepancy with notes "h" and "pp" as related to the ADS instrumentation TS, and that a license amendment was being developed.

5.1.3 Cracked Pipe in Core Spray Instrument Line

On August 24, 1995, during a routine surveillance test, an equipment operator reported a small leak (near valve V-20-159) on a 3/4-inch instrument line for core spray system 2. The instrument line originates at the booster pump discharge 10 inch common piping, and provides the high side pressure input to the RV-40B booster pump differential pressure (dp) switch. The licensee evaluated the condition and entered TS 3.4.A.3, a 7-day Action requirement for core spray system 2. At the time, the licensee considered several factors while assessing the situation, including 1) RV-40B provides an input to ADS, 2) there is a potential for spraying adjacent equipment if the instrument pipe ruptures, and 3) long term operation of the core spray system could possibly reduce the torus volume upon an instrument pipe rupture during an accident.

The licensee completed repairs of the cracked pipe, satisfactorily tested the system, and exited the TS on August 26. However, due to ineffective verbal and written communications and weak work practices, the cracked pipe was cut in such a manner that the damaged section could not be preserved for failure analysis. The associated material nonconformance report (95-33) and job order (64013, Step 5.2) stated to "cut off section of pipe with crack approximately 2 inches above the sockolet." In addition, the quality verification manager provided similar verbal instructions to the responsible mechanical maintenance supervisor. The work was performed on a subsequent shift and the pipe was cut at the crack. A quality verification representative confirmed that the internal and external surfaces of the remaining section were intact. The pipe was then re-welded, inspected and tested. The licensee plans to review the details related to this missed opportunity to develop corrective actions. They also plan to evaluate the portion of pipe that was removed to the extent possible to determine the cause of the pipe failure.

5.1.4 Automatic Depressurization System Technical Specifications (Open, URI 50-219/95-15-03)

During a followup review of the August 24 core spray system instrument pipe break, the inspector identified a discrepancy with ADS TS 3.1.A, Table 3.1.1, Item G.3. High drywell pressure, triple-low reactor water level, and AC voltage are listed for the ADS function, Items G.1, G.2, and G.3, respectively. However, the inspector found that the AC voltage item listed in the TS does not reflect the actual plant configuration. The intent of the AC voltage item was to provide an interlock to prevent a pre-programmed reactor pressure vessel blowdown if AC power should not be available to the emergency bus (indication that core spray system in unavailable). Rather, the actual plant configuration uses the booster pump differential pressure (dp) switches to confirm operation of the core spray system as a permissive to the ADS initiation logic.

The licensee informed the inspector that there was substantial discussion and correspondence during the initial licensing and TS issuance for Oyster Creek (circa 1967-1968) regarding item G.3. GPUN disputed the need for an AC voltage interlock, however, it became incorporated into the TSs. At the end of this inspection, the licensee was reviewing older correspondence to determine when item G.3 was added to the TSs. It did not appear that item G.3 was requested by GPUN as part of a TS change request.

Notwithstanding the chronology and basis for the existence of G.3 in the TSs, the licensee never implemented a conceptual design of the AC voltage interlock. Nor were TSs changed to reflect the actual plant design and configuration. Instead, pressure switches in the booster pump discharge piping were used as an input to the ADS logic. However, it was not clear whether those pressure switches were in the original system design or were added after initial plant startup via a modification. Those pressure switches were subsequently modified in 1985 (SE 402760-001) by replacing them with the existing dp switches. The purpose of the modification was to resolve concerns associated with postulated scenarios in which the pressure switches could malfunction and not perform their intended function. The safety evaluation stated that the modification did not require a TS amendment.

The licensee stated that, although they recognized that TS item G.3 did not apply and that a TS change request was not submitted, they treat the inoperability of the dp switches as an entry into TSs. However, the inspector found that only the 7-day Action requirement of TS 3.4.A.3 was entered for the August 24 pipe crack; no ADS instrumentation TS Action requirement was implemented.

The licensee stated that they were in the process of developing a TS change request to address item G.3. For the interim, they stated that they would develop and document a formal Licensing Opinion to provide operator guidance for actions (with respect to system operability) for both the core spray and ADS systems as related to dp switch problems.

The inspector expressed concern that the licensee was knowledgeable of the TS discrepancy, however, specific actions had not been taken to resolve the issue. The inspector discussed the need for the licensee to determine whether similar known TS discrepancies exist for which additional interim guidance is necessary.

Additional information is necessary to determine details regarding the addition of item G.3 to TSs. Pending a further review of this event, including a determination of 1) the basis for not processing a TS amendment following the 1985 modification and 2) whether additional similar conditions exist, this is an unresolved item. (URI 50-219/95-15-03)

5.1.5 Conclusions

The licensee properly planned, executed, and supervised repair activities for failed pressure switch RV-29D. Conversely, the activities associated with the failure analysis of the cracked core spray instrument pipe were not well controlled, supervised, or executed. As a result, the critical area of the failed pipe section was damaged during the maintenance.

Both activities revealed TS inconsistencies requiring corrective action. Most significantly, the licensee's knowledge of an inaccurate TS line item as compared to the actual plant configuration demonstrated weakness in maintaining the licensing basis.

5.2 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 inspectors assessed the LER to determine whether further onsite review was needed.

Licensee Event Report

- LER 94-020 discussed an inadvertent isolation of the containment ventilation and purge system due to operator error. While performing a surveillance test to channel 1 of the system, the operator inadvertently manipulated channel 2 and caused two valves to isolate. The licensee restored the system to normal, and successfully completed the test. This event was discussed in NRC Inspection 50-219/94-26. This LER is closed.

Periodic Reports

- Monthly Operating Report for July, 1995.

- March 1995 INPO Evaluation. The inspector noted that findings were consistent with NRC findings. No additional NRC followup is warranted or planned.

5.3 Review of Previously Opened Items

(Closed) Unresolved Item 50-219/93-81-01. This item dealt with transient and operational cycle monitoring, tracking and recording. During the Operational Safety Team Inspection (OSTI), 50-219/93-81, the inspectors identified that a running total of the number of cycles of operating transients, identified as design basis in the Updated Final Safety Analysis Report (UFSAR), since the beginning of plant operation, had not been fully maintained. As a consequence of this, the licensee could not evaluate the current fatigue life usage of those components designed with a limited number of cycles.

In a General Electric Company (GE) Service Information Letter (SIL) issued in December, 1979, it was recommended that GE BWR owners monitor reactor vessel duty cycles and duty cycle frequency to predict the numbers of duty cycles the plant will be subjected to during its 40-year life. In Supplement 1 to GE SIL 318, issued June 2, 1993, GE cancelled this recommendation and recommended that GE BWR owners perform fatigue usage calculations based on more realistic thermal duty cycles than those used in the original fatigue evaluation of the equipment.

In a letter dated July 26, 1990, concern was expressed by the GPUN mechanical components manager that the 120 startup/shutdown cycles on which the original vessel fatigue analysis had been based had already been exceeded by 46 cycles. However, a justification was given by GPUN, at that time, that showed the designs to be adequate if a less conservative assumption is made of the characteristic of the thermal duty cycle. Reactor stud bolting was found to have high usage factors and consideration was given to replacement of the studs. Subsequently, a justification by GPUN, based on a more realistic interpretation of thermal duty cycles, indicated that stud replacement was not required.

In June 1992, logging of thermal transient cycles began at Oyster Creek. Since the logging practice began in 1992, it was necessary to search the operational data since startup of the plant to determine the actual number of thermal duty cycles so fatigue evaluations could be performed.

Since the OSTI inspection (October 1993), GPUN has actively been searching for operating data prior to 1992 and reevaluating the fatigue life usage of primary components under the guidance of more realistic estimates of thermal duty cycles. Oyster Creek has improved its data collection system to provide for an ongoing monitoring of thermal duty cycles.

The inspector reviewed a copy of Guidelines for Transient Cycle Logging and found a procedure in which the shift technical advisor (STA) kept current a Transient/Cycle Summary Sheet that logged 14 different types of transients. These are compared to the design transients and the engineering department is notified when there is any possibility that the estimated lifetime transients will be exceeded.

The inspector reviewed the compilation of cyclic data prior to 1992 obtained by Oyster Creek engineering. This difficult task was completed satisfactorily by researching semi-annual reports, monthly operating reports, STA status sheets, availability status sheets, operator generator logs, control room logs, and operations strip charts. These data were included in the updated compilation of operating cycles to provide for a realistic estimate of current component fatigue usage factors.

The inspector reviewed GPUN reanalysis calculation sheets which compared the original design fatigue usage factors with the usage factors obtained using more realistic estimates of thermal cycles. It was found that the design startup/shutdown cycles could be increased to 300 cycles, as compared to the original 120 cycles, without the components exceeding a limiting cumulative usage factor of 1.0 over the plant operational lifetime. This eliminates the concern that the design cycles had been exceeded.

GPUN found that the two areas of concern in fatigue evaluation of the primary system components were the reactor vessel studs and the reactor vessel seal skirt. Reevaluating these components, GPUN found the estimated lifetime cumulative usage factor of the studs is .225 and that of the skirt is .9439. Since these values are below the cumulative usage factor limit of 1.0, the primary system component usage factor estimates are satisfactory.

The inspector concluded that the licensee's analysis of component fatigue usage factors was accurate and complete. Unresolved Item 50-219/93-81-01 is closed.

6.0 EXIT INTERVIEWS/MEETINGS (71707)

6.1 NRC Region I SALP Management Meeting and Plant Tour

On August 24, 1995, the NRC Region I, Regional Administrator and the Region I, Deputy Director, Division of Reactor Projects (DRP), toured the Oyster Creek facility, interviewed several licensee managers, and convened a public meeting to present the NRC's Systematic Assessment of Licensee Performance (SALP) to senior licensee management. The assessment was presented by the Deputy Director, DRP with open discussions between the NRC and the licensee concerning SALP topics. The slides used in the NRC presentation are attached.

6.2 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on September 20, 1995. 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; 47 of the direct inspection hours were performed during backshift periods, and 8.5 of the hours were deep backshift hours.

UNITED STATES NUCLEAR REGULATORY COMMISSION

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE (SALP)

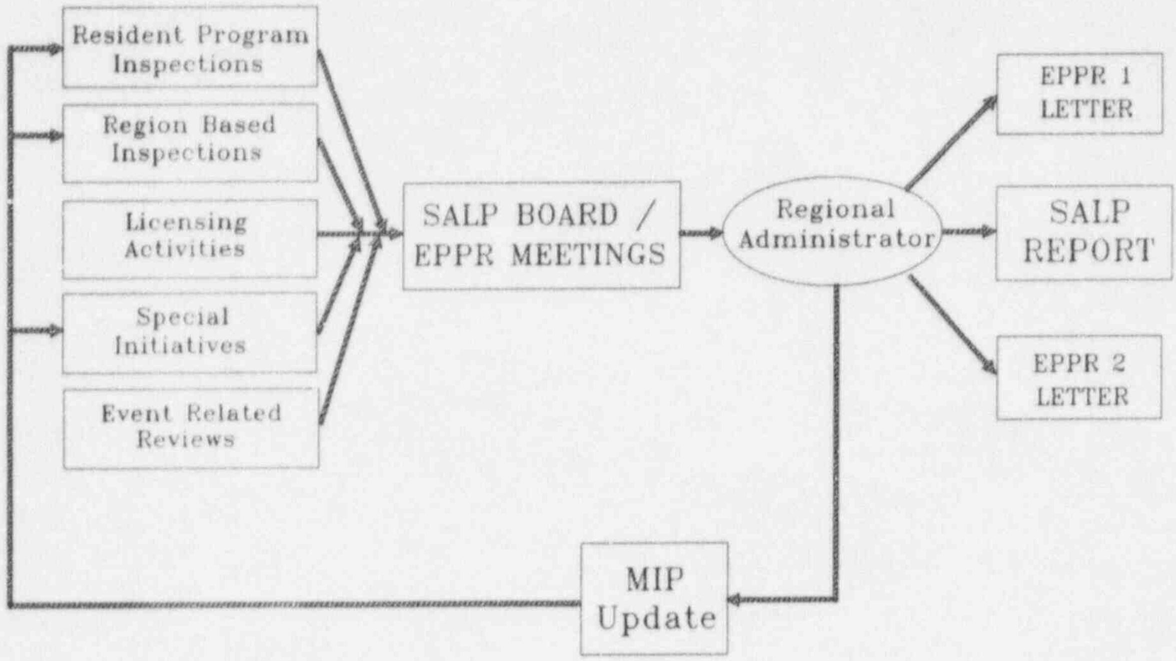
OYSTER CREEK NUCLEAR STATION

ASSESSMENT PERIOD: DECEMBER 12, 1993 - JUNE 24, 1995
BOARD MEETING: JULY 6, 1995
MANAGEMENT MEETING: AUGUST 24, 1995

Agenda

NRC Introductory Remarks:	**Tim Martin** **Regional Administrator**
GPUN Introductory Remarks:	**Phil Clark** **President - GPU Nuclear**
NRC SALP Process and Results:	**Wayne Lanning** **Deputy Director** **Division of Reactor Projects**
GPUN Closing Remarks:	**Phil Clark**
NRC Closing Remarks:	**Tim Martin**
Public Questions and Answers:	**NRC**

SALP / EPPR PROCESS



Performance Analysis Areas For Operating Reactors

- Plant Operations
- Engineering
- Maintenance
- Plant Support
  - Radiological Controls
  - Emergency Preparedness
  - Security
  - Fire Protection
  - Housekeeping

Performance Category Ratings

Category 1: **Superior Performance**
- Programs and Procedures Provide Effective Controls
- Self-Assessment Efforts are Effective
- Corrective Actions are Comprehensive
- Minimum Inspections to Verify Safety

Category 2: **Good Performance**
- Programs and Procedures Normally Provide Controls
- Self-Assessment Efforts are Good - Emerging Issues
- Recurring Issues
- Additional Inspection to Assess Performance

Category 3: **Acceptable Performance**
- Programs and Procedures are Weak
- Self-Assessment Efforts are Reactive
- Corrective Actions less than Adequate
- Significant NRC and Licensee Attention Required

Performance Analysis

Functional Area	Rating Last SALP	Rating This SALP
Plant Operations	2	1
Maintenance	2	2
Engineering	1	1
Plant Support	2	2

PLANT OPERATIONS
Category 1

- STRONG MANAGEMENT INVOLVEMENT IN DAILY AND PREPLANNED OPERATIONAL EVOLUTIONS
  - WEAK MANAGEMENT CONTROL OF STATION BLACKOUT COMBUSTION TURBINES

- IMPROVEMENTS SINCE LAST SALP
  + ENTERING TS LCO DURING SURVEILLANCES
  + FORMAL OPERABILITY REVIEW AND ANALYSIS
  + ADMINISTRATIVE CONTROL PROCEDURE FOR TROUBLESHOOTING ACTIVITIES

- STRONG OPERATOR PERFORMANCE

- STRONG OPERATOR TRAINING PROGRAM

- GOOD COGNIZANCE / CONTROL OF MAINTENANCE ACTIVITIES, PARTICULARLY DURING REFUELING OUTAGE

- OPERATOR PERFORMANCE ISSUES
  - FAILED TO FOLLOW PROCEDURES FOR HCU WORK
  - CORE ALTERATION PERFORMED WITHOUT DIRECT SUPERVISION

- CANDID AND THOROUGH SAFETY ASSESSMENTS

MAINTENANCE
Category 2

- MANAGEMENT CONTINUED TO PROVIDED GOOD OVERSIGHT
  - \+ COMPREHENSIVE OUTAGE RISK PROCESS
  - \+ EFFECTIVE PREVENTIVE MAINTENANCE PROGRAM

- STRONG PERSONNEL EXPERTISE / PLANT KNOWLEDGE

- VERY GOOD PLANT MATERIAL CONDITION

- IMPROVED SURVEILLANCE PROGRAM
  - \+ EQUIPMENT OPERABILITY INTEGRATED INTO PROCEDURES
  - \+ ULTRASONIC EXAMINATION TECHNIQUE DEVELOPED FOR VALVE STEM CRACKING PROBLEM
  - \+ GOOD VISUAL INSPECTION OF CORE SHROUD

- PLANT CHALLENGES CAUSED BY COMMUNICATIONS, CONTROL, OVERSIGHT / TECHNICAL SUPPORT PROBLEMS
  - \- SECONDARY CONTAINMENT COMPROMISED
  - \- UE FROM WORK PERFORMED OUTSIDE OF THE WORK SCOPE
  - \- SD TRIP SIGNAL DURING TESTING OF RECIRC SYSTEM

ENGINEERING
Category 1

- STRONG MANAGEMENT INVOLVEMENT
  - \+ EFFECTIVE RESOLUTION OF PLANT PROBLEMS
  - \+ GOOD COMMUNICATIONS WITH PLANT ORGANIZATIONS
  - \+ EFFECTIVE CONTROL OF WORK BACKLOGS
  - \+ QUALITY PLANT MODIFICATIONS / SAFETY EVALUATIONS

- CONTINUED EXCELLENT ENGINEERING WORK
  - \+ THOROUGH CALCULATIONS AND ANALYSES FOR MODIFICATIONS
  - \+ HIGH QUALITY OPERABILITY ANALYSES
  - \+ THOROUGH TROUBLESHOOTING ANALYSES

- STRONG PERFORMANCE IN TECHNICAL PROGRAMS

- SIGNIFICANT WEAKNESS IN EDG MODIFICATIONS
  - \- CRITICAL FLAWS IN MANAGEMENT OVERSIGHT AND CONTROL
  - \- STRONG RELIANCE ON SINGLE ENGINEER
  - \+ PROMPT AND THOROUGH CORRECTIVE ACTIONS

PLANT SUPPORT
Category 2

- CONTINUED EFFECTIVE RADIATION PROTECTION PROGRAM
  - \+ STRONG MANAGEMENT SUPPORT FOR ALARA
  - \- CHALLENGED BY THE HIGH IN-PLANT SOURCE TERM
  - \- PROBLEMS WITH CONTROL OF SHIELDING
  - \+ EXCELLENT INTERNAL EXPOSURE CONTROL AND ASSESSMENT PROGRAM
  - \+ EFFECTIVE RADWASTE/MATERIALS PROGRAM

- CONTINUED EXCELLENT RADIOLOGICAL ENVIRONMENTAL MONITORING AND EFFLUENT CONTROL PROGRAMS

- GOOD EMERGENCY PREPAREDNESS PROGRAM PERFORMANCE

- GOOD SECURITY PROGRAM PERFORMANCE
  - \+ IMPROVED MAINTENANCE OF SECURITY EQUIPMENT
  - \- PERSONNEL PERFORMANCE ISSUES
  - \- REPETITIVE LIGHTING DEFICIENCIES

- EXCELLENT PLANT HOUSEKEEPING