U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	94-10
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:	April 19, 1994 - May 30, 1994
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John Rogge, Section Chief
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Date

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

The unit was operated safely. Operators quickly and effectively responded to an abnormal response of the control rod drive (CRD) system during surveillance testing activities. However, subsequent related troubleshooting activities were performed without sufficient planning, and resulted in a challenge to both the operators and the plant. Control room operators were alert in noticing a coincidental increase in the drywell unidentified leak rate shortly after problems were experienced with CRD 34-39; that observation assisted in confirming a suspected cause.

Maintenance

The maintenance and surveillance activities observed during this inspection were conducted safely by knowledgeable personnel. Troubleshooting and repair activities associated with the activities associated with replacement of the 'B' control rod drive pump stop-check valve and the reactor building closed cooling water valve (V-5-106) were well controlled in accordance with approved procedures and work packages.

Engineering

Engineering support to develop modifications for the "A" and "B" CRD system stop-check valves were effective. System engineering provided good support to operations personnel after a cooling water leak was suspected for CRD 34-39. Engineering personnel properly identified and evaluated a concern related to isolation condenser valve closure times being greater than the FSAR stated design basis.

Plant Support

Periodic observation by the inspectors of station workers and radiological controls and security program requirements noted proper implementation by the licensee. An emergency preparedness drill conducted on May 11, 1994, identified some weaknesses which are being positively addressed by an additional practice drill.

Safety Assessment/Quality Verification

The licensee identified and promptly assessed the safety significance of several incorrectly connected local power range monitor (LPRM) detectors. Licensee initiatives taken to address this problem identified a method of verifying LPRM detector connections from the control room which will reduce personnel exposure during future LPRM verification activities.

(EXECUTIVE SUMMARY CONTINUED)

Multiple examples of improperly anchored and stored loose equipment were identified throughout the plant. This is indicative of a programmatic weakness, and is a violation of Technical Specifications. The licensee took positive corrective action to either inspect all Whiting crane main hoist couplings or suspend their use when a defective coupling was identified during a crane modification. The licensee also took action to inform other licensees of the potential defective couplings.

DETAILS

1.0 PLANT OPERATIONS (71707, 93702)

1.1 Operations Summary

The plant was operating at 100 percent power at the beginning of the period, and continued to operate at full power until May 22, 1994, when the unit initiated a Technical Specification required shutdown due to a failed stop-check valve in the control rod drive (CRD) system. Repairs to the CRD system were made and the unit was taken critical on June 1, 1994 and reached full power at 1:13 a.m. on June 3, 1994. The unit continued operation at 100 percent power through the end of the inspection period.

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
- fire pump building

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 Technical Specification Required Shutdown Due to Valve Failure

On May 22, 1994, Oyster Creek initiated a Technical Specification (TS) required shutdown following the failure of a stop-check valve in the control rod drive (CRD) system. There are two CRD pumps, each of which is provided with a two-inch stop-check discharge valve. A single suction flowpath from the condensate storage tank branches into the two parallel CRD pump suction lines, which again form a common line on the discharge of the pumps.

Prior to the shutdown, the plant was operating at 100% power with the "B" CRD pump in service. At about 10:00 a.m. on May 22, operators started a monthly CRD operability surveillance test (procedure No. 617.4.001). The "A" CRD pump was placed in service, and then the "B" pump was secured. At that time, the operators received a CRD low charging water pressure alarm and noted that all CRD flowrates (e.g., charging water, drive water, cooling water) indicated zero flow. The "B" CRD pump was immediately restarted, and CRD system parameters returned to normal. The operators again removed the "B" CRD from service about 15 minutes later. This time, an additional operator was stationed at the pump to observe its performance. The response was the same (i.e., loss of CRD flow). This time, however, the operators did not immediately restart the "B" pump, and that pump subsequently began rotating backwards. The "B" stop-check valve had apparently failed to properly seat, and the CRD system flow configuration became such that the discharge flow from the "A" pump was returning to the CRD system suction piping via the "B" pump. As a consequence, CRD flow was not being provided to the reactor and the hydraulic control units.

Operators unsuccessfully attempted to stop the reverse flow situation by manually closing the "B" stop-check discharge valve. Then they closed the "B" suction valve, however, the suction relief valve lifted (set to lift at 250 psig). Subsequently, the "A" CRD pump was stopped for about one minute in order to terminate flow. The operators then initiated two start attempts for the "B" CRD pump; each time the pump failed to start due to a low suction pressure trip (cause of the pump start failure was not know at the time). The low suction pressure trip was subsequently determined to be a result of over-ranging the pressure switch when the "B" suction valve was closed, pressurizing the suction piping between the pump and the suction valve. The "A" CRD pump was then restarted. After additional mechanical agitation to the "B" stop-check discharge valve, CRD flows were regained, however, they were slightly low.

The operators declared the entire CRD system inoperable, and initiated a controlled plant shutdown, as required by TSs (to Cold Shutdown within 30 hours). Cold Shutdown was reached at 6:30 a.m. on May 23. While placing the shutdown cooling (SDC) system in service, the operators found that a reactor building closed cooling water (RBCCW) system motor operated butterfly valve (No. V-5-106) had failed such that RBCCW flow from the SDC heat exchangers could not be remotely operated from the control room, but was controlled using individual SDC heat exchanger outlet valves. The valve stem-to-operator key was subsequently replaced to allow local operation of V-5-106; a valve positioner problem was also repaired. The cooldown was otherwise accomplished without complications. The licensee notified the NRC in accordance with the reporting requirements of 10 CFR 50.72.

Following the shutdown, the licensee inspected both CRD stop-check valves, and identified that inadequate design appears to have been the cause for the valve failure. Specifically, the valve stem loosely fit into the valve disc, thereby allowing the plug to cock inside the valve body. Valve seat damage was noted, apparently due to the improper seating of the valve. In addition, the licensee used the stop-check valve as a throttle valve to maintain charging water pressure between 1390 psig and 1510 psig; a non-conventional application for a stop-check valve. Throttling of the valve is believe to have contributed to accelerated valve wear due to erosion effects.

No foreign materials or damage from possible foreign material was evident during the valve inspection activities. Following the shutdown, the "B" CRD pump was successfully started. However, this time, the "A" stop-check valve apparently did not close as expected. The operator began to manually close the valve, at which time he heard the valve fully close. As a result of the failure of the "A" stop-check valve to close without operator action, the licensee planned to inspect both valves. The seating surface for the "A" stop-check valve was found to be slightly degraded, which was subsequently lapped successfully. In addition, the "A" stop-check valve stem and disc were replaced. The new stem/disc arrangement is such that the stem more positively guides the valve disc. The damage to the "B" valve was more severe, and required replacement. The licensee subsequently modified the "B" train to provide a similar stop/check arrangement by using two separate valves. The "B" CRD pump was run to determine whether any pump damage occurred during the event, due to either foreign material or from reverse rotation; no abnormal conditions were identified. The licensee successfully recalibrated the pressure switch.

The inspector reviewed the licensee's activities following this event, including the operator responses, and the repair activities and the modifications performed for both the "A" and "B" stop-check valves. The operator's activities were initially prompt and appropriate in that the abnormal CRD system response was quickly identified and the system returned to normal. However, the inspector determined that the second attempt (15 minutes later) to remove the "B" CRD pump was not appropriately planned and executed. That evolution resulted in a prolonged loss of the CRD system. Specifically, a restart attempt for the "B" CRD pump was delayed and resulted in excessive reverse flow through the pump. This is an example of operations department "troubleshooting," as previously identified as a weakness in NRC Inspection Report 50-219/93-11 due to the lack of a program to formally plan, evaluate, and execute operations and/or system engineer led troubleshooting activities. The licensee is currently developing a standard for both the operations and system engineering departments in response to the identified weakness. In this case, a shutdown would still have been required in order to repair the "B" stop-check valve, however, a more systematic troubleshooting approach may have minimized the challenge to both the operators and the plant. The inspector determined that the licensee's overall investigative and corrective actions following the shutdown were appropriate.

2.0 MAINTENANCE (62703, 61726)

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 inspector observed portions of the following activities.

Job Order (JO)	Description
JO 03306	Determine Cause of Service Water and Emergency Service Water Discharge Line Foaming and Correct (Minor Maintenance);
JO 51157	Repack Isolation Condenser Steam Inlet Valve V-14-31;
JO 53170	Replace Directional Control Valve 120 Withdrawal Solenoid;
JO 53173	Replace Directional Control Valve 123 Insert Solenoid;
JO 53294	Replace NC-52A and NC-52B Stabilizing Valve Filters;
JO 53753	No. 1-2 Reactor Building Closed Cooling Water System Heat Exchanger Tube Cleaning;
JO 54331	Troubleshoot and Repair V-5-106.

2.2 Surveillance Activities

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

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

Procedure No.	Test
607.4.004	Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test
664.3.006	Fuel Zone Level Channels "C" and "D": Ancillary Components Calibration and Test
609.4.001	Isolation Condenser Valve Operability and In Service Test

The inspectors noted that properly approved procedures were in use, approvals were obtained and prerequisites satisfied prior to beginning the tests, 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 procedures.

3.0 ENGINEERING (71707, 40500)

3.1 Leaking Cooling Water Supply to Control Rod Drive 34-39

On April 24, 1994, control room operators received a high temperature alarm for control rod drive No. 34-39. The control rod position was fully withdrawn, and operators applied a stall flow signal to the CRD. That action temporarily cleared the alarm (for about four hours). The operators again applied a stall flow signal to CRD 34-39, however, the high temperature alarm did not clear. The temperature for CRD 34-39 was in excess of 483°F; normal CRD temperatures are approximately 200°F.

Coincident with the CRD 34-39 high temperature alarm and related activities, the control room operators noted an increase in the indicated drywell unidentified leak rate (DULR), from 0.8 gpm to 1.3 gpm. In an attempt to confirm that the increase in the DULR was related to CRD 34-39, the operators isolated the cooling water to the CRD. The CRD drive temperature increased by 32°F (483°F to 515°F) in 15 minutes, and the DULR gradually decreased toward 0.8 gpm, thereby confirming the suspected relationship. The temperature increase of 32°F indicated that there was still some small amount of cooling flow reaching the CRD with the cooling flow unisolated. In addition, the observed increase in the DULR is comparable to the amount of CRD cooling flow normally provided to a properly functioning CRD cooling line.

The CRD system engineer (SE) was involved in diagnosing and evaluating the observed CRD 34-39 leakage. The SE also discussed the potential cause(s) for the observed indications with General Electrical (GE). The leak is believed to be in the CRD insert path; most likely, near the flanged connection of the CRD to the CRD housing. However, the licensee concluded that the connection is generally intact because some cooling water does reach the CRD when it is valved in, and the control rod notches in and out acceptably. Based upon discussions between the SE and GE, the effect of isolating a CRD will not significantly impact control rods scram times. The only potentially significant impact is one of a maintenance issue; the CRD seals could degrade due to the elevated temperature. As a result, the licensee has listed CRD 34-39 as a top priority for drive replacement in the upcoming Fall 1994 refueling outage.

At the end of the inspection period, the licensee had developed several actions in order to trend the performance of CRD 34-39. Those actions include performing a weekly stall flow check (vice the normal monthly stall flow check) of CRD 34-39; the last five weekly stall flows were between five and six gallons per minute. The SE stated that notching difficulties may be experienced if stall flows reach seven or eight gallons per minute. The operators also notch the CRD weekly; no notching difficulties were apparent. The SE stated that if notching difficulties are experienced, then the associated control rod would be valved out of service and declared inoperable, and the requirements of Technical Specification 3.2.B would be followed (six control rods may be valved out of service provided the related core reactivity limitations are satisfied). In addition, GE has determined that a minimum reactor pressure of 500 psig is required to provide the motive force to reliably scram control rods. As a result, during the two reactor startups during this period, the reactor engineering group modified the control rod withdrawal sequence to ensure that reactor pressure was greater than 500 psig when control rod 34-39 was withdrawn.

The inspector reviewed the licensee's evaluation of the leak identified on CRD 34-39, and concluded that the efforts of both the operations and system engineering personnel were appropriate.

3.2 Isolation Condenser Valve Closure Times Greater Than Design Basis

On April 22, 1994, the licensee completed an engineering analysis that determined that the isolation condenser (IC) DC-powered isolation valves may not close within the assumed 60 second isolation time as specified in the FSAR (Section 6.3.2.5). The analysis was performed as part of the licensee's Motor Operated Valve (MOV) Program, per NRC Generic Letter (GL) No. 89-10. The supporting calculations assumed worst-case postulated design conditions, and yielded a total IC isolation of 81.5 seconds for IC "A", and 76 seconds for IC "B." Previous calculations had not considered the effects of torque and voltage on DC motor speed. In addition, the licensee's GL 89-10 MOV program requires the licensee to consider higher valve factors and valve stem friction coefficients. One AC-powered and one DC-powered MOV is provided in each steam (inlet) line and each condensate (outlet) line for each condenser (i.e., two DC-powered valves for each IC). The licensee reported this condition (outside the design basis of the plant) to the NRC in accordance with the reporting requirements of 10 CFR 50.72 on April 22, 1994.

The purpose of the IC system is to remove heat from the reactor vessel when the reactor is isolated from the main condenser. The IC system is designed to automatically isolate from the reactor vessel in the event of a high energy IC line break. The licensee performed an analysis that concluded that a 95 second total IC isolation time bounds the existing design conditions. Therefore, this event is of minimal safety significance.

The licensee stated that an FSAR change will be processed to reflect the longer allowable IC isolation criteria of 95 seconds. The inspector reviewed the licensee's actions, participated in a conference call with GPUN and NRC Region I and Headquarters personnel, and concluded that the licensee's actions were appropriate.

4.0 PLANT SUPPORT (71707, 82301)

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.

4.3 Emergency Preparedness

On May 11, 1994, the inspector observed portions of an emergency preparedness drill being conducted by the licensee in preparation for their annual exercise, which is scheduled for June 8, 1994. The major events of the drill were a turbine trip without a reactor scram (ATWS) which resulted in fuel damage, in addition one main steam isolation valve closed very slowly with a main steam line break in the turbine building. These events led to an offsite release that was supposed to result in the declaration of a general emergency. The general emergency declaration did not take place because of a communication problem. On May 12, 1994, the licensee critiqued the previous days performance. The emergency drill observers noted several strengths and weaknesses identified during performance of the drill including communication difficulties and the failure to declare a general emergency. The emergency preparedness personnel stated that performance during the drill was satisfactory but not at the level expected. A second drill was scheduled to be performed on June 1, 1994, to focus on and correct the problems identified during the May 11 drill.

The inspector determined that the licensee performed a detailed critique of the May 11 drill and that positive steps were being taken to correct identified problems.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

5.1 Licensee Event Report (LER) and Periodic Report Review

NRC inspectors reviewed the following LERs 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 94-03 described a turbine trip and reactor scram due to the failure of a proportional amplifier that supplied the density compensation signal to both the A and B steam flow signals. The LER fully discusses the cause of the reactor scram. The reactor scram was also discussed in NRC Inspection Report 50-219/94-07. This LER is closed.

- LER 94-04 described a condition outside the design basis of the plant in which worst-case condition calculations resulted in isolation condenser valve closure times in excess of existing FSAR design values. This issue is discussed in Section 3.2 of this report. The inspector closed this LER.

Periodic Reports

- Monthly Operating Report for April, 1994

5.2 Incorrectly Wired Local and Average Power Range Monitors (LPRM & APRM)

On May 16, 1994, while withdrawing control rod 34-19 from notch 18 to notch 48 (rods for flow swap), the control room operator noted that LPRM 36-17 did not exhibit the expected indication. The operations department and core engineering subsequently performed a traversing incore probe (TIP) trace in conjunction with control rod movement to verify that LPRM 36-17 was incorrectly connected. Core engineering initiated a review of LPRM depletion traces and identified two other LPRMs (12-14 and 20-09) that appeared to be incorrectly connected. These LPRMs were determined to be incorrectly connected, on May 17 and 18, 1994, by their response to control rod motion.

Each LPRM string consists of four detectors (A, B, C and D) arranged vertically in the core. The 'A' detector is 18 inches up from the bottom of the core with each of the other detectors spaced at 36-inch intervals. There are 31 LPRM strings. Sixteen of the 31 LPRM strings provide inputs to 8 APRM channels where core power is averaged. Each APRM channel receives input from 4 LPRM strings from either the 'A' and 'C' level or the 'B' and 'D' level (8 LPRM detectors for each APRM).

The following incorrect connections were identified by the licensee:

- LPRM 12-41 had its 'B' and 'D' inputs to APRM channel 6 switched with each other.

- LPRM 20-09 had its 'B' and 'D' inputs to APRM channel 7 switched with each other.

- LPRM 36-17 had its 'A' and 'B' inputs to APRM channels 4 and 8 switched with each other such that the incorrect detector core height local power signal was fed to the incorrect APRM channel.

As noted above, after discovery of the first incorrectly connected LPRM, core engineering initiated an immediate review of LPRM depletion curves. The review resulted in the identification of two additional incorrectly connected LPRMs. Core engineering initiated a reanalysis of the core 14 reload safety analysis with the identified connection errors. It was determined that the 'B' and 'D' swaps had no effect. Further analysis was conducted on LPRM 36-17 'A' and 'B' detector swaps to ensure that it did not create a reduction in the ability to monitor or protect the reactor under both static and accident conditions. Core engineering determined that there would be no effect on core parameters. As a precaution additional combinations of switched LPRMs were input into the analysis to determine if there were any particularly detrimental combinations that could occur, none were identified.

The inputs from the 12-41 and the 20-09 LPRMs were changed at the instrument cabinets under a temporary modification to maintain configuration control. The connections will be corrected under the reactor vessel during the 15R outage then returned to normal in the cabinet. LPRM 36-17 could not be rewired at the cabinet because it would violate electrical separation criteria between the different APRM channel (4 and 8) cabinets. It was decided to perform a 50.59 review and safety evaluation to determine if the LPRM inputs to the incorrect APRM connections could be left as is and declared operable. Core engineering analysis determined that it was acceptable. A temporary modification was issued to maintain configuration control of the system. The connections will be corrected under the reactor vessel during the 15R outage.

On May 19, 1994, the inspector attended the plant review group (PRG) meeting which discussed this problem. Numerous combinations of LPRM/APRM connection errors and their consequences were discussed with core engineering and other personnel present. It was determined that due to cable length under the reactor vessel only detectors within each LPRM could be swapped, which limited the possible combinations. A safety analysis for the limited number of incorrect connections, identified as possible, determined this was not a safety significant problem. The PRG discussed what options were available to ensure that there were no other incorrectly connected LPRMs. Two methods were determined to be viable, one involved moving control rods and observing LPRM response the other was the use of time domain reflectometry (TDR), which had not previously been used to verify LPRMs at this facility. It was decided to try TDR to determine if it could be used to verify proper detector connections. If TDR results were acceptable it could be used to verify LPRM connections and minimize personnel exposure and transients on the fuel induced by rod movement. The PRG performed a further review of LPRM detector depletion curves to determine if any additional LPRMs exhibited any indication that they might be incorrectly connected. Five other LPRMs exhibited minor indications that they could possibly be incorrectly connected. It was decided to use TDR on the three LPRM originally identified and the five questionable LPRMs. Results of the use of TDR were very positive, the five questionable LPRMs were verified to be correctly connected and the three original LPRMs were verified to be as determined by prior rod movement verification. The licensee subsequently used TDR to verify that all remaining LPRMs were correctly connected.

The inspector determined that the licensee had taken proper actions to identify and correct, where possible, incorrectly connected LPRMs and that core engineering took prompt action to identify additional LPRMs. Core engineering promptly performed reanalysis of the core 14 reload to ensure core parameters both static and transient were not affected by the incorrectly connected LPRMs. In addition, the licensee verified that TDR could verify LPRM connections from the control room in conjunction with, or in place of under reactor vessel verification. TDR verification appears to be an excellent means to help minimize personnel radiation exposure received during under vessel verification of LPRM connections.

5.3 Improperly Secured Equipment in the Plant (Violation 50-219/94-10-01)

During the last routine resident inspection (50-219/94-07), the inspector identified to licensee management specific deficiencies regarding storage of loose equipment in the plant. The particular area was a safety related battery charger for the "C" 125 volt vital battery. During this inspection period, the inspector reviewed the licensee's procedure and its implementation for storing and securing equipment in the plant. Several additional deficiencies were identified.

Oyster Creek administrative procedure No. 119.5, "Loose Equipment Storage," provides the instructions to station personnel for storing loose equipment in the reactor building (RB) and turbine building (TB) during all modes of operation. The procedure requires that loose equipment in the RB and TB shall be seismically anchored or removed when the plant is in a Run or Startup mode. The procedure requires that items on wheels or rollers will be restrained to the existing building structure, or inhibited from rolling using a four wheel chock arrangement (shown as an attachment to procedure 119.5). The items are not to be restrained by connecting them to pipes, pipe supports, cable trays, or conduit supports. For items without wheels or rollers, procedure 119.5 requires that the minimum distance to any nuclear safety related (NSR) or regulatory required (RR) component shall be equal to the height of the unrestrained items plus 12 inches (minimum of 12 inches only for inherently stable items). Finally, the procedure specifies that compressed gas cylinders shall be securely attached to the building structure by at least two 3/8" thick nylon ropes, located approximately at 1/3 and 2/3 the cylinder height from the floor.

While touring the Oyster Creek facility, the inspector identified multiple examples of the licensee's failure to meet the requirements of procedure 119.5 Those examples are as follows:

- In April 1994, the inspector noted scaffolding and other transient material was staged close to, and some equipment was leaning on safety related DC Charger #1 for the "C" vital battery (See Inspection Report 50-219/94-07, Paragraph 1.2);

- Subsequent to correction of the above deficiencies, at DC Charger #1, the inspector identified an unsecured tool chest on wheels located near DC Charger #1, and two breakers on wheels (secured with angle iron; inherently stable items) located less than 12 inches (approximately three inches) from DC Charger #1;

- On RB 23 ft. elevation, scaffolding and lifting equipment was chained adjacent (less than 12 inches away) to safety related motor control center (MCC) No. DC-1 (apparently in preparation for work on an adjacent containment spray system);

- On RB 23 ft. elevation, a large equipment lifting structure on wheels was stored with only two wheels chocked. In addition, the two chocking devices were very loose, thereby providing minimal restraint;

- On TB 23 ft. elevation, a compressed air cylinder was loosely tied with a single rope to a vertical piece of electrical conduit (not to building structure with two ropes);

- On TB 23 ft. elevation (outside the 4kV vital area boundary), several portable scaffold sections and lifting devices, as well as tool boxes (on wheels), were not secured or restrained; and

- Throughout several areas of the plant, many gas compressed cylinders were secured with only one chain or nylon rope (vs. two per procedure 119.5).

These concerns were identified to the Director, Operations and Maintenance, who initiated corrective action for the specific deficiencies. The inspector concluded that the multiple examples listed above are indicative of a programmatic weakness in the licensee's implementation of the loose equipment control program. Technical Specification 6.8.1 requires that written procedures should be established, implemented and maintained that meet or exceed the requirements of NRC Regulatory Guide 1.33. The licensee's failure to comply with the requirements of Oyster Creek Station Procedure No. 119.5, "Loose Equipment Storage," constitutes a violation of Technical Specification requirements. **(Violation 50-219/94-10-01)**

5.4 Defective Main Hoist Couplings in Overhead Cranes

During recent turbine building crane modifications the licensee identified defective couplings whose failure could result in a dropped load. The coupling is located between the main hoist DC motor and the hoist gearbox. There are two DC brakes that disengage when the main hoist motor is energized and engage to hold the load when the main hoist motor is deenergized. A DC brake is located on each end of the long motor drive shaft. If the coupling failed while lifting a load the load would fall until the operator could release the hoist button to deenergize the motor and engage the brake.

During modifications to the turbine building crane (Whiting, 150 ton main hoist, 40 ton auxiliary hoist) the license identified a casting defect in the main hoist motor to gear box coupling. The coupling is two sections, the driver and the driven, the face section is (all numbers approximate) 10.5 inches in diameter with a thickness of 1.75 inches on the outer rim, the raised center portion (shaft collar) is an additional 1.5 inches thicker than the face portion and 6 inches in diameter with a shaft hole of 2.75 inches in diameter. The coupling is 'sand cast' to the approximate size and shape then machined to specifications specified on a drawing for a specific (by serial No.) crane. The coupling defect identified started at the machined edge where the collar joins the large diameter face section and penetrated through the collar into the keyway. There was no evidence of propagation of the defect and the crane had passed all previous load tests. The defect appears to be an original casting defect dating back to the 1960s. The coupling was replaced by a forged steel coupling machined by American Crane Co.

As a result the licensee inspected the reactor building crane (Whiting, 100 ton main hoist, 5 ton auxiliary hoist) main hoist to gear box coupling (same approximate size as turbine building crane coupling). The licensee identified a defect in a location (machined edge where the shaft collar joins the face section) similar to the turbine building crane. The licensee examined the coupling using magnetic particle testing and identified defect propagation of about 2 inches on both sides of the defect. The licensee on discovery of the defect on the reactor building crane issued directions not to use the heater bay crane (Whiting) until the coupling could be inspected. They also ordered two new sets (4 sections) of motor to gear box couplings from Whiting Crane for the reactor building crane. Both sets of new couplings were rejected by the licensee due to minor and major surface pitting identified during receipt inspection and were returned to Whiting. Whiting has agreed to machine new couplings for the reactor building crane and will perform radiography tests to ensure the couplings are acceptable.

The licensee also inspected the auxiliary hoist couplings on both the turbine building and the reactor building crane and did not identify any defects in the couplings. In addition, to suspending use of the reactor building crane's main hoist and the heater bay crane the licensee will make a voluntary report to the NRC and has made a 'nuclear network' notification to alert other facilities of the possibility of coupling defects.

The inspector determined that the licensee had taken positive corrective action to either inspect all couplings of other Whiting cranes or suspend their use. The licensee also alerted other facilities of the potentially defective couplings through the nuclear network notification.

6.0 EXIT INTERVIEWS/MEETINGS (40500,71707)

6.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on June 10, 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; 70.5 of the direct inspection hours were performed during backshift periods, and 24.5 of the hours were deep backshift hours.

6.2 Attendance at Management Meetings

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

Date	Lead Inspector	Subject	Report No.
4/22/94	L. Eckert	Radcon	50-219/94-09

At the above meeting the lead inspector discussed preliminary findings with senior GPUN management.