U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-219/85-13

Docket No. 50-219

License No. DRP-16 Priority -- Category C

Licensee: GPU Nuclear Corporation

100 Interpace Parkway

Parsippany, New Jersey 07054

Facility Name: Oyster Creek Nuclear Generating Station

Inspection At: Forked River, New Jersey

Inspection Conducted: April 1 - May 5, 1985

Inspectors: E L Conner for 5/15/85
W. H. Bateman, Senior Resident Inspector date

E L Conner for 5/15/85
J. F. Wechselberger, Resident Inspector date

R. J. Urban 6/3/85
R. J. Urban, Reactor Engineer date

Approved by: E L Conner 6/3/85
E. L. Conner, Chief, Reactor Projects date
Section 1A, Projects Branch No. 1,
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Inspection Summary:

Routine onsite inspections were conducted by the resident inspectors and one region based inspector (289 hours) of activities in progress including plant operations, physical security, radiation control, housekeeping, emergency preparedness, chemistry, surveillances, plant modifications, and system functional testing. The inspectors also reviewed licensee action taken to address previous inspection findings, potentially generic issues, and Circulars. In addition, the inspectors made routine tours of the control room and the plant and followed up on anonymous allegations.

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Results: The inspection activities identified two violations: one was failure of Maintenance and Construction (M&C) and QA to follow procedures controlling Quality Deficiency Report (QDR) responses (discussed in paragraph 12), and the other was failure to review and approve procedure temporary changes within 14 days as required by Technical Specifications (discussed in paragraph 16). An issue involving apparent hanger discrepancies was unresolved and three open items were closed.

Several allegations were investigated; and, although portions of them were substantiated, none were determined to significantly impact safe operation of the plant.

DETAILS

1. Summary of Plant Activities

At the beginning of the report period, the plant was operating at reduced power to repair a leak in a main flash tank. The repairs were successful and power was increased. Power level throughout most of the period was between 620 and 650 MWe. Minor adjustments to power output were required because of difficulties staying below the core thermal limits for MAPLHGR.

The drywell unidentified leak rate was consistently low and drywell identified leakage was steady at the normal level. Identified leakage did increase slightly at the end of the period because of a failed #2 seal on the 'E' recirculation pump. Control room temperature recorder problems continued. A safety relief valve (NR-28P) started leaking slightly as indicated by its acoustic monitor and tailpipe temperature. The effects of the leak were not seen in any changes in drywell parameters. A leak was identified in secondary containment (a crack in the reactor building roof) and was temporarily repaired. At the end of the period, the 'B' isolation condenser outlet valve had been declared inoperable because of failure to open during a routine surveillance.

Two events drew public attention. The first involved a small chlorine leak from the chlorination system. An Unusual Event was declared for a short period of time. The leak was minor and was quickly corrected with no harm to plant personnel. The second involved contamination of five workers and a portion of the refueling floor during operations to fill the spent fuel shipping cask with demineralized water. The five individuals and the floor were decontaminated and a determination made by whole body counting that none of the workers received any uptake of radionuclides.

Secondary side problems continued throughout the period. The main flash tank leaked again midway through the period and the turbine was taken off-line to make repairs. Offgas flow increased due to vacuum leaks which were eventually identified and fixed. Offgas system performance was erratic in that the system tripped many times on low flow; troubleshooting remained in progress at the end of the period. The 'C' condensate pump seal started leaking; repairs could not be made during operation. Miscellaneous valve bonnet and packing leaks were repaired. Condenser vacuum appears to be lower than expected, based on cooling water temperatures; the licensee is concerned for plant thermal efficiency. Apparent inadequate ventilation in the feedpump room is causing higher than normal temperatures on the feedpump motor stator bearings. At least once, plant power had to be decreased because of high stator bearing temperatures.

NRC licensing examinations were conducted and preliminary results indicated the test results were good.

Receipt of spent fuel shipments from West Valley continued without any major problems. Reracking of fuel assemblies in the spent fuel pool to accommodate the West Valley shipments continued. Problems were encountered with binding between two sections of the refueling mast and a close tolerance fit between the fuel grapple and the new high density spent fuel racks. Both problems were corrected. Radiation levels have increased in the vicinity of the fuel pool cooling heat exchangers due to radioactive material from the West Valley spent fuel plating out and lodging in the heat exchangers.

The Post-Accident Sampling System (PASS) was reportedly completed by the April 29 commitment date, although it was not possible to demonstrate its ability to draw pressurized liquid samples from the reactor coolant system because of a leaky containment isolation valve. The licensee applied for and received an extension from NRC licensing to postpone demonstration of PASS operability until the leaky containment isolation valve can be repaired. Problems were encountered with both channels of the H_2O_2 analyzer system (another NUREG-0737 required item). In particular, both channels of the H_2O_2 analyzers were inoperable at various times during the period.

A quarterly emergency drill was conducted and the new Technical Support Center (TSC) was used. Information flow appeared to be improved from the previous drill.

2. Licensee Action on Previous Inspection Findings

(Open) Noncompliance (219/84-09-2C): Failure to properly consider fire protection and security in design of new cable spreading room.

The licensee stated that the vital area concerns expressed in paragraph 10.2.2 of Inspection Report 84-09 have been evaluated and determined to be acceptable as is. This item will remain open pending additional NRC review.

(Closed) Inspector Followup Item (219/84-09-10): Clarification of the licensee's commitment as to the type of 10 CFR 50 Appendix J leakrate test to be performed on the Reactor Head Cooling containment isolation valve.

The licensee clarified that both Type A [illegible] Type C testing are performed on valve V-31-2. The inspector revie[illegible] following procedures to ensure both Type A and C tests are performed [illegible]-2:

- Station Procedure 665.5.006, Rev. 8, "Local Leak Rate Tests." Figure 665.5.006-XVII specifically addresses the local leakrate testing of V-31-2 and Data Sheet #42 provides for recording leakage measurements.

- Station Procedure 666.5.007, Rev. 7, "Primary Containment Integrated Leak Rate Test," Paragraph 8.3.7 requires that the Reactor Head

Cooling system be lined up per Attachment 666.5.007-6. Attachment 666.5.007-6 requires V-31-2 be shut, thus including it as a containment pressure boundary.

After reviewing these procedures, the inspector had no further concerns.

(Closed) Unresolved Item (219/84-07-01): Verification of torus shell UT thickness measurements performed during the 1977 outage.

In 1977, the torus shell was emptied to perform welding repairs for pitted and corroded areas in the submergence phase. The licensee stated that UT thickness measurements taken in 1977 showed that the required minimum thickness of .385 inch was met. The inspector reviewed selected UT thickness measurements taken in 1977. All records reviewed showed thicknesses to be in excess of minimum requirements.

(Closed) Unresolved Item (219/84-07-02): UT thickness measurements for vapor phase of torus shell.

During the 1977 outage, torus shell thickness measurements were made when the torus was empty. These measurements indicated there was no corrosion in the vapor phase of the torus. The two additional areas examined during the 1983-1984 outage, as discussed in Inspection Report 84-07, indicated again that there was no corrosion in the vapor phase of the torus shell.

The inspector reviewed the results of the UT thickness measurements to confirm the data. All records reviewed showed torus shell thickness measurements to be in excess of minimum requirements.

(Open) Inspector Followup Item (219/85-06-02): Observe future Isolation Condenser surveillance of valve V-14-35 to verify operability.

At the end of this report period, V-14-35 failed to open during surveillance testing. The valve motor tripped out on thermal overload when an attempt was made to open the valve. The valve was subsequently manually opened, and it was observed to take an abnormal amount of effort to break the valve disc free from its closed position. Both electrical and mechanical operation of the valve were normal after the initial freeing-up of the valve, i.e., the problem could not be repeated to facilitate troubleshooting. MOVATS testing was performed on the Limitorque operator but results did not indicate the cause of the problem. The licensee elected to declare the valve inoperable, which placed them in a seven day Tech Spec limiting condition for operation. The problem remained at the end of the report period. The inspectors will continue to follow licensee activities to locate and correct the cause of the problem.

3. Plant Operation Review

3.1 Routine tours of the control room were conducted by the inspectors during which time the following documents were reviewed:

-- Control Room and Group Shift Supervisor's Logs;

-- Technical Specification Log;

-- Control Room and Shift Supervisor's Turnover Check Lists;

-- Reactor Building and Turbine Building Tour Sheets;

-- Equipment Control Logs;

-- Standing Orders; and,

-- Operational Memos and Directives.

The reviews indicated that the logs were acceptable, although improvement could be made if additional detail was included when unusual events occur. A suggestion was made to the licensee that a Limiting Condition for Operations log be started. This log would record each time the plant entered a Tech Spec action statement that was time dependent. The licensee agreed to evaluate the proposal. Control room housekeeping and behavior were also observed and found to be acceptable with an exception noted during the conduct of the NRC licensing walk-through examination. In particular, a licensing examiner had to stop his examination of a candidate because of excessive noise in the control room. The Group Shift Supervisor was informed of the problem, whereupon corrective action was taken and the examination resumed.

3.2 Routine tours of the facility were conducted by the inspectors to make an assessment of the equipment conditions, safety, and adherence to operating procedures and regulatory requirements. The following areas were among those inspected:

-- Turbine Building;

-- Vital Switchgear Rooms;

-- Cable Spreading Room;

-- Diesel Generator Building; and

-- Reactor Building

The following items were observed or verified.

a. Fire Protection

-- Randomly selected fire extinguishers were accessible and inspected on schedule.

-- Fire doors were unobstructed and in their proper position.

-- Ignition sources and combustible materials were controlled in accordance with the licensee's approved procedures.

-- Appropriate fire watches or fire patrols were stationed when equipment was out of service.

b. Equipment Controls

-- Jumper and equipment markups were in accordance with TS requirements.

-- Conditions requiring the use of jumpers received prompt licensee attention.

-- Administrative controls for the use of jumpers and equipment markups were properly implemented.

c. Vital Instrumentation

-- Selected instruments appeared functional and demonstrated parameters within TS Limiting Conditions for Operation.

d. Housekeeping

-- Plant housekeeping and cleanliness were in accordance with the approved licensee programs.

3.3 The inspectors directly reviewed the Containment Spray system to verify that the system was properly aligned in the standby mode. This inspection included:

-- Verification that each accessible valve in the flow path was in the correct position by either visual observation of the valve or remote position indication;

-- Verification that power supply breakers were aligned for components that must actuate upon receipt of an initiation signal;

-- Visual inspection of the major components for leakage, proper lubrication, cooling water supply, and other general conditions that might prevent fulfillment of their functional requirements; and,

-- Verification by observation that instrumentation essential to system actuation or performance was operational.

The following discrepancies were identified.

-- V-21-38, Heat Exchanger 1-4 Shell Vent, was found open; the valve lineup required the valve to be closed.

-- V-3-85, Emergency Service Water Relief Valve; Containment Spray Heat Exchanger 1-4 relief setpoint lockwire was broken.

-- V-21-1021, ESWP-5 Pressure Indicator Isolation Valve, was found open (mechanically frozen) and the gauge connection plugged (Gauge Removed); the valve lineup required "gauge removed", "plugged closed" and "valve closed." The lineup had been checked and verified to be as specified by the valve lineup.

-- Numerous discrepancies were found in the valve check-off list for Containment Spray system delineated in Procedure 310 Revision No. 18.

-- Numerous discrepancies were found in the P&ID diagram Containment Spray System (GE 148F740 Rev P16).

-- Rebar (reinforcing bar) was found welded to the Containment Spray piping downstream of V-21-17.

-- Hanger NQ-2-H39 was found not supporting the Containment Spray piping as designed.

-- An indentation was found in the Containment Spray piping at the common discharge line from Containment Spray pumps 1-1 and 1-2. The indentation was formed as a result of a bolt, welded to the north east corner room stairway, coming in contact with the pipe.

These discrepancies were discussed with the licensee who agreed with them and committed to take corrective action.

4. Emergency Preparedness

During this report period, the licensee conducted an emergency drill as part of their program to test the emergency response capability of their organization's procedures and personnel. The inspectors observed portions of the drill and concluded:

-- The use of standard terminology when referring to plant equipment would improve communications.

-- The radiological telephone line in the Technical Support Center (TSC) should be moved from the Coordinator/Director's desk area to the radiological support room.

-- The radiological assessment status board in the TSC was not updated.

-- The parameters given to the plant operators after the drill initiation are not indicative of actual plant response and aid to confuse the operators in responding to the accident.

-- The TSC coordinator needs an assistant to update the status boards.

-- The overhead screens used to provide plant status was an improvement.

-- Scenario development needs improvement.

These observations were presented to the licensee management during the exit interview. The licensee had developed similar concerns in their critique of the emergency drill and plans action to improve in these areas.

5. Observation of Physical Security

During daily entry and egress from the protected area, the inspector verified that access controls were in accordance with the security plan and that security posts were properly manned. During facility tours, the inspector verified that protected area gates were locked or guarded and that isolation zones were free of obstructions. The inspector examined vital area access points to verify that they were properly locked or guarded and that access control was in accordance with the security plan.

No inspector concerns were identified.

6. Radiation Protection

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 that monitoring instruments were functional and in calibration. Posted extended Radiation Work Permits (RWPs) and survey status boards were reviewed to verify that they were current and accurate. The inspector observed activities in the RCA to verify that personnel complied with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area.

An event occurred during filling and venting operations of the TN-9 spent fuel shipping cask that resulted in the contamination of five workers and a portion of the refueling floor. In particular, defective quick-disconnect hose fittings resulted in a spray of water (estimated to be not more than one gallon) from the cask vent line when the cask was filled. This spray was the source of the radioactive contaminants. Radcon personnel operated quickly and effectively to isolate the area and start cleanup operations. The five workers were decontaminated and given a whole body count whereupon it was determined no uptake of radionuclides was involved.

7. Surveillance Testing

The inspectors reviewed and witnessed performance of the following surveillance tests to determine if the tests were included on the master surveillance schedule, were technically adequate, and were performed at the required frequency and in accordance with procedure.

-- Torus to Drywell Vacuum Breaker Operability Test, 604.4.006, Revision 9.

-- Isolation Condenser Valve Operability and Inservice Test, 609.4.001, Revision 12.

From this review, it was determined the surveillances were performed in accordance with procedures.

The licensee notified the inspectors of missed surveillances involving monthly testing of 4160 volt emergency bus undervoltage devices; specifically, the "no voltage" and "degraded voltage" devices were not tested. The explanation for the missed surveillances was that Plant Engineering had failed to revise controlling procedures to incorporate the surveillance requirements imposed by the recent issuance of Amendment 80 to the TS. Upon discovery of the missed surveillances, immediate action was taken to perform the surveillances. The licensee has issued a LER to identify and address the problem. Inspector follow-up of this event is continuing and all issues will be addressed during closeout of LER 85-008.

8. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to TS 6.9.1 were reviewed by the inspector. This review included the following considerations: the report includes the information required to be reported to the NRC; planned corrective actions are adequate for resolution of identified problems; and that the reported information is valid. The following reports were reviewed during this report period.

-- March 1985 Monthly Operating Report

-- Cycle 10 Startup Report

No inspector concerns were identified.

9. Follow-up of a Potentially Generic Issue

The inspectors reviewed a potentially generic issue concerning Hancock control rod drive hydraulic control unit valves. The potential problem with these valves involves failure of the stem to disc interface because of intergranular stress corrosion cracking. The separation of the disc from the stem could affect the scram function of the rod associated with the defective valve. GE In-Service Information Letter 419 recommends that potentially affected licensees implement a preventive maintenance program to help prevent failure of the Hancock valves. The inspectors questioned Plant Engineering to determine plans to address this issue and determined that sampling inspection of potentially-affected valves will be scheduled during the Cycle 11 refueling outage scheduled to begin in April 1986. The Region I office staff is tracking this matter on a generic basis.

10. Inspection of Actions Taken by Licensee in Response to GE Service Information Letter (SIL) No. 402 (TI 2500/12)

NRC Temporary Instruction (TI) 2500/12 was issued to guide inspection of licensee activities in response to GE SIL No. 402, "Wetwell/Drywell Inerting." The objective of the TI was to determine whether the licensee had implemented the actions recommended in the SIL to satisfy the safety concerns raised by the Hatch Unit 2 vent header crack.

By letter dated September 14, 1984, GPUN provided a response to the NRC regarding GE SIL 402 which concerns the implementation of recommendations to ensure injection of cold nitrogen into the containment will not occur. The recommendations are discussed below:

1. Evaluate Inerting System Design

The licensee committed to complete this evaluation during the present operating cycle and implement any needed modification during the Cycle 11 refueling outage. The evaluation is not yet complete.

The inspector reviewed P&ID 13432.19-1 Nitrogen Purge and Makeup System and discussed the system design with plant engineering. Liquid N_2 is stored in an outside tank. When placed in service for inerting, the N_2 is vaporized by electrically heated vaporizers and flows through a thermostatic low temperature cutoff valve. For makeup, there is an ambient air vaporizer supplemented by an electric heater to maintain N_2 temperature greater than 50 degrees Fahrenheit. The injection points for both makeup and inerting are into the 18 inch purge line

for the drywell and into the 20 inch reactor building to torus vacuum breaker line for the torus. Hence, the N_2 injection point differs from Hatch. This recommendation will be reviewed again when the licensee completes their evaluation. (219/85-13-01)

2. Evaluate Inerting System Operation

The licensee indicated that they have experienced operational difficulties with the inerting system electric heated vaporizer in the past. The vaporizer, low temperature cutoff valves, and the N_2 tank are owned and maintained by the vender. To eliminate some of the operational problems, GPUN indicated that they now require equipment condition reports from the vendor. This was made a contractural requirement; but, as of this writing, GPUN is not in receipt of the N_2 inerting system inspection reports from the vendor. These reports will be reviewed once GPUN makes them available for inspection. (219/85-13-02)

The inspector reviewed Procedure 312, "Reactor Containment Integrity and Atmosphere Control" used for containment inerting. This procedure requires the operator to maintain N_2 temperature between 65-80°F. There is also a caution in the procedure to ensure N_2 temperature never drops below 40°F to prevent cracking of piping systems. The inspector also verified that the temperature and flow indicator calibrations are current. This recommendation has been adequately addressed with the exception of review of the equipment condition reports.

3. Inspect Nitrogen Injection Line

The inspector reviewed inspection records which documented ultrasonic and/or radiograph inspection of accessible welds of piping up to the last isolation valve for the drywell and wetwell penetrations. This recommendation had been adequately addressed.

The remaining recommendations relating to drywell/wetwell bypass leakage test and containment inspection were addressed during inspector review of Bulletin 84-01 in Inspection Report 85-01.

11. IE Circulars

An attempt was made during this report period to review licensee action taken to address a 1980 Circular. It was determined that the licensee had not addressed the Circular, nor was the Circular included in their action item tracking system. A further review indicated that the particular Circular was not an isolated case and that a good number of Circulars had not been addressed. Upon realization of the problem, the licensee agreed to address each open Circular on the resident inspectors' Outstanding Item List. The inspectors considered this corrective action appropriate and had no further concerns.

12. Plant Modifications

The inspector observed a QA/QC hold tag on the Post Accident Sampling System (PASS) control panel. The reason for the hold tag was to identify that Maintenance and Construction (M&C) had bypassed QC holdpoints during the construction phase of the PASS. The inspector followed up to determine the particular hold points bypassed. During this follow-up, the inspector asked if there were additional problems with bypassed QC holdpoints and it was determined that Quality Deficiency Report (QDR) 84-67 dated June 1984 and QDR 84-75 dated August 1984 (which incorporated QDR 84-67) had been written to address two problems: the first was M&C bypassing of QC holdpoints and the second was M&C performance of safety-related work prior to QC awareness of the work activity, thus precluding QC from establishing holdpoints.

Because of the recently-identified holdpoint bypass problem with the PASS, the inspector asked QC for details regarding the corrective action taken by M&C to address this problem. QC informed the inspector that M&C had not yet responded to QDR 84-75 and that it had been escalated to the Vice President of M&C for action. The inspector was concerned over this apparent disregard by onsite M&C management of their responsibilities to comply with the requirements of the Oyster Creek QA/QC program, specifically, to respond to the QDR within 30 days. QA procedure 1000-ADM-7215.02, Revision 0-00, GPUN Quality Deficiency Reports, requires the action party (in this case M&C) to provide their written corrective action response within 30 days or to request an extension in writing. The failure of M&C to offer any written response to the QDR is contrary to the requirements of Criterion XVI and V of Appendix B of 10 CFR 50 and is a violation (219/85-13-03). It was noted during review of this concern that QA/QC had not properly implemented their escalation procedures. Had they done so, the matter quite possibly could have been resolved in a more timely manner and at a lower level of management. This was discussed with QA/QC management.

Subsequent to identification of the violation, M&C addressed in writing the QC holdpoint bypass issue. The effectiveness of their corrective action will be evaluated during the next outage. Still remaining to be addressed are the issues of why safety-related work was performed prior to QC review of the work scope to establish holdpoints and why M&C failed to respond to the QDR.

13. Startup Testing - Post Accident Sampling System

During this report period, the inspectors witnessed functional testing of the gas sampling portion of the PASS. Liquid samples could not be drawn from the reactor coolant system because: (1) the containment isolation valves in the line through which the samples are drawn are closed to comply with Tech Spec requirements governing a leaking containment isolation valve; and (2) the plant was at power, thus precluding taking a depressurized sample. Several repeats of the gas sampling portion of the test were required because of PASS equipment problems and unavailability of local

sample analysis capability. By the end of the report period, the gas sampling portion of the procedure had been satisfactorily completed. The NRC order to have PASS operable by April 29, 1985, was extended by NRC licensing to the next target of opportunity to repair V-24-29, the leaking containment isolation valve. Upon repair of this valve, the ability of the system to draw liquid samples from the reactor coolant system will be tested to verify total PASS operability.

14. Pipe Supports

Observations of pipe supports during walkdown of the Containment Spray system resulted in the following two observations:

-- Support NQ-2-H39 was not performing its function, i.e., there was an approximate 3/8" gap between the support and the bottom of the pipe. (The support is designed to support, from underneath, the deadweight of a horizontal pipe run).

-- Support H 0327 was installed during the recent Cycle 10 outage. The resident observed that it is actually an anchor. Because it is an anchor, it precludes variable load hangers installed on connected piping runs from performing their design function; i.e., they will not support different loads as temperatures change.

The inspectors questioned the licensee as to the technical rational for the above two installations. In the case of support NQ-2-H39, it was determined that an inspection conducted November 5, 1984, identified the existence of the gap. At the end of the report period, the licensee was not able to tell the NRC inspector who had performed the inspection and whether or not the deficient condition had been technically reviewed and dispositioned. The apparent incorrect installation of support NQ-2-H39 is an unresolved item pending determination by the licensee of who performed the inspection and identification of the technical disposition to accept the incorrect installation after it was identified. (219/85-13-04)

Support H 0327 was installed as part of a modification during the Cycle 10 refueling outage to provide torus water cleanup capabilities. In discussions with the Technical Functions cognizant support engineer, it was indicated that a stress analysis had been performed on the piping affected by the addition of the support/anchor and that no thermal growth stress problems resulted from the modifications. The inspector had no further questions.

15. Allegations

Eleven allegations were received by Region I in an anonymous letter on March 27, 1985. Five of these allegations lacked specificity and, therefore, were not inspected as part of this review. The remaining six allegations were reviewed onsite as discussed below.

15.1 Allegation No. 1

a. Allegation

It was alleged the public address system was overloaded and could not sustain extended use.

b. NRC Inspection Findings

During the 1983 - 1984 outage, the licensee suspected that their public address (PA) system might be overloaded because voltage measurements indicated 25 volts; most PA systems are powered by 70 volts. Subsequently, the licensee hired an independent contractor to assess the possible problem. The contractor found the PA system to be powered by 25 volts, normal for this older model system. The contractor determined the system to be at about 140% capacity, but not overloaded. This is due to the fact that even under constant use by a human voice, spaces, irregularities, and peaks (normalities in a human voice) would not allow the system to overload. However, if the PA system was to be used constantly (like playing background music), it would be overloaded. During an emergency, the only time the system would be in "constant" use would be to sound station alarms. Since this would never exceed a minute, the system would not be in jeopardy.

The licensee's PA system is powered by approximately 13 amplifiers; nine are solid state amps (80% eff.), and four are tube amps (30% eff.). The licensee plans to replace the tube amps with solid state amps in June 1985, thereby increasing the system's efficiency and bringing the system load down to about 100% from 140%.

The inspector concluded that the licensee's present PA system is capable of performing its design function. Planned modifications by the licensee will improve the system.

15.2 Allegation No. 2

a. Allegation

It was alleged that there are constant chlorine leaks in the plant's chlorine system.

b. NRC Inspection Findings

The inspector questioned the licensee concerning leaks in the chlorine system. There have been only four substantial leaks in the past several years. However, there are leaks every time the chlorine bottles are changed (about every two weeks) because of residual chlorine remaining in the system header. Although nitrogen is used to purge the system before breaking the pigtails,

some residual chlorine still remains. The human nose is very sensitive to chlorine (.02-.2 ppm) and one can constantly smell the fumes in and around the chlorine house. The odor is similar to being in a filter house at a municipal swimming pool; the odor remains even though there are no leaks.

The inspector noted that during the inspection the licensee was in the process of revising Procedure 326, "Chlorination System," Rev. 10 dated 3/17/85, to improve the procedure and make it more understandable. The licensee had recently installed a chlorine leak detection monitor system at the chlorine house. If a leak were to occur, an alarm would sound in the control room. The Group Shift Supervisor (GSS), in accordance with Procedure 2000-ABN-3200.3, "Toxic Material Release," Rev. 0 dated 9/1/84, would announce to clear the area by the chlorine house, isolate the control room, and dispatch personnel (with Scott Airpacks) to contain the leak. If the leak was large and could not be contained, the GSS would refer to the Oyster Creek Emergency Plan.

The inspector determined that there are not constant chlorine leaks in the system and that the licensee has focused attention in this area to make its operation safer and more reliable. The licensee has measures to ensure the health and safety of their employees.

15.3 Allegation No. 3

a. Allegation

It was alleged that the overboard discharge radiation monitor rarely works and that this fact is not recorded.

b. NRC Inspection Findings

The inspector found that the radwaste overboard liquid radiation monitor has been inoperable 100% of the time for about the last three years. However, the licensee has been operating in accordance with their Technical Specifications (TS). When the monitor is inoperative, the licensee is required to analyze two independent samples of any tank to be discharged, one prior to discharge and one near completion of discharge; also, two station personnel shall independently check valving prior to discharge of radioactive liquid effluents.

The inspector reviewed past records concerning radioactive liquid effluent discharges. Each discharge is authorized by a permit. Forms 20.0019.0022.0002, "Liquid Release Isotopic Summary" and 816.16, "Radioactive Liquid Waste Analysis and Release Permit" were inspected carefully to determine if the licensee was complying with their TS. The inspector determined

that: (1) the inoperability of the monitor is officially recorded on Form 816.16; (2) the monitor is inoperable 100% of the time; (3) two independent samples are analyzed, one prior to discharge and one near completion; and (4) two station personnel independently check valving prior to discharge.

This allegation is unsubstantiated because the licensee is in compliance with their TS which allows the subject monitor to be inoperable if certain precautions are taken.

15.4 Allegation No. 4

a. Allegation

It was alleged that work orders (Short Forms) were, in many cases, not traceable and were not completed prior to restart from Cycle 10 refueling outage. It was also alleged these Short Forms were ignored so the plant could start up regardless of NRC requirements.

b. NRC Inspection Findings

Each Short Form originated at Oyster Creek is assigned a number: therefore, every Short Form is traceable. Short Form 15029, dealing with the 1-8 sump hi-lo level alarm, was submitted with the allegation and was followed up by the inspector. The licensee was able to retrieve this Short Form and it was found to be open. Short Form 15029 was originally scheduled under Budget Activity (B/A) 402015; however, it was not an Incomplete Worklist (IWL) item. Additional submitted documentation stated that outstanding IWL items for B/A 402015 have been completed, reviewed and closed. Since Short Form 15029 was not an IWL item, the licensee was in agreement with their close out form. In addition, Short Form 15029 was subsequently removed from B/A 402015 by an interoffice memorandum dated 3/5/85; it was originally scheduled under the wrong B/A number.

The licensee performed a very complete and thorough review of all issues in their Restart Readiness Log. All items that had to be completed before restart were finished and the remaining items were placed on the Master IWL Log. The inspector reviewed the log and found the total to be less than 50 items, greatly reduced during the past several months.

This allegation is unsubstantiated because Short Forms are traceable and tracked and because IWLs were properly dispositioned during the Readiness to Restart Review.

15.5 Allegation No. 5

a. Allegation

It was alleged that a responsible onsite manager did not meet radiation training and requalification requirements.

b. NRC Inspection Findings

In accordance with the Code of Federal Regulations, Part 19, personnel are to be trained in the area of radiation protection. The individual involved has maintained his training up-to-date. The NRC does not require all personnel to have a respirator fit, only those personnel that will be entering airborne radioactivity areas; the individual has not entered this type of area. The NRC does not require whole body counting unless the person will enter an airborne radioactivity area. However, Oyster Creek Procedure 915.8, "Bioassay Program," and 9300-ADM-4025.01, "Bioassay Procedure," requires personnel with RWP training to have a whole body count once per year. On 1/26/84, the individual upgraded his training to RWP status but did not have a whole body count. Therefore, the individual was not in conformance with station procedures from 1/26/84 to 1/4/85. After questioning the licensee regarding this matter, it was brought to the inspector's attention that two other management personnel also did not have current whole body counts. The licensee corrected this situation by revoking their thermoluminescent dosimeters (TLDs).

This allegation was partially substantiated in that the individual did not have a whole body count from 1/26/84 to 1/4/85; however, there was no violation of NRC requirements. Since the individual was in accordance with station procedures upon inspection, and considering that he had not entered any RWP areas during 1984, no problem exists.

15.6 Allegation No. 6

a. Allegation

It was alleged that many plant drawings of record, especially electrical drawings, do not represent the actual as-built configuration.

b. NRC Inspection Findings

The licensee stated that many of their electrical drawing do not reflect the as-built plant. They are currently spending more than one million dollars per year in an effort to update their drawings. The licensee has approximately 23,000 drawings, 199 of which are control room drawings. The 199 control room

drawings are considered the most important drawings regarding plant operation and are, therefore, kept current by specific plant procedures.

This allegation is true to the extent that some official drawings of record (green drawings) do not represent as-built conditions. The licensee is aware of this situation and has been working and will continue to work to resolve the problem. The inspector will continue to follow this item (85-13-06).

16. Review of Temporary Changes

The inspectors reviewed temporary changes to insure an adequate review was being conducted and that the reviews were being conducted in accordance with Technical Specifications and the licensee's procedures. The inspectors examined temporary changes associated with four safety systems and found a number of temporary changes that exceeded the 14-day review required by Technical Specifications. This was discussed with the Safety Review Manager, who agreed to run a computer printout of temporary changes completed during the last month. The printout reflected approximately 20% of the temporary changes completed during this period were reviewed and implemented after the 14 day time requirement had expired. Technical Specification 6.8.3 requires temporary changes to procedures to be documented, reviewed, and approved within 14 days of implementation. This is a violation of Technical Specifications. (50-219/85-13-05)

The licensee's Operation Quality Assurance Group issued a Quality Deficiency Report (QDR) No. 84-107, dated 12/17/84, on the timeliness of temporary change reviews. In response to the QDR, the licensee decided to implement measures to improve the efficiency of the review and to conduct preliminary reviews (Quality Assurance, radiological controls, etc.) after the Responsible Technical Review (RTR) and implementing approval. The licensee's Procedure 107, "Procedure Control," Revision 25, requires that preliminary reviews be conducted prior to performing a RTR. Technical Specifications requires the review and implementing approval to be completed within 14 days. Although Technical Specifications do not clearly specify that a preliminary review be conducted prior to the implementing approval, it is implicit that a complete and thorough review be conducted within 14 days to determine that an unreviewed safety question does not exist.

Operations Quality Assurance has periodically sampled the temporary change process based on the findings in QDR No. 84-107, with approximately the same result. On 3/25/85 the QDR was escalated to a higher level of management for resolution. Operations Quality Assurance has decided to examine some of the temporary changes that have taken longer to complete the review process to determine the cause for the delays and if the temporary change should have been processed as a revision.

17. Unresolved Items

An unresolved item requires further review to determine its acceptability. Paragraph 14 contains an unresolved item.

18. Exit Interview

At periodic intervals during the course of this inspection, meetings were held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of this inspection. Those in attendance at this exit interview are listed below. The licensee stated that of the subjects discussed at the exit interview and written in this report, no proprietary information is included.

GPU

J. Barton, Deputy Director Oyster Creek
T. Corrie, QC Manager
R. Fenti, QA Manager, Mod/Ops
P. Fiedler, V. P. and Director Oyster Creek
E. Growney, Safety Review Manager
R. Heward, Vice President Radiological & Environmental Control
D. Holland, Oyster Creek Licensing Manager
N. Kazanis, Director Quality Assurance
B. Leavitt, Radiation Control
W. Popow, Maintenance and Construction Director
M. Radvansky, Manager, Tech Functions
W. Smith, Plant Engineering Director
W. Stewart, Acting Manager-Operations
J. Sullivan, Plant Operations Director
E. Wright, Tech Functions

USNRC

W. Bateman, Oyster Creek Senior Resident Inspector
R. Urban, Reactor Engineer
J. Wechselberger, Oyster Creek Resident Inspector

Nuclear

GPU Nuclear Corporation
Post Office Box 388
Route 9 South
Forked River, New Jersey 08731-0388
609 971-4000
Writer's Direct Dial Number:

April 18, 1985

Mr. Harry B. Kister, Chief
Projects Branch No. 1
Division of Reactor Projects
U.S. Nuclear Regulatory Commission
Region I
631 Park Avenue
King of Prussia, PA 19406

Dear Mr. Kister:

Subject: Oyster Creek Nuclear Generating Station
Docket No. 50-219
Inspection 85-01
Notice of Violation Response

Pursuant to 10CFR2.201, the attachment to this letter contains our response to the Notice of Violation in Appendix A of your letter dated March 14, 1985. Due to management reviews, several additional days beyond the due date were necessary to finalize our response. Messrs. E. L. Conner and H. Kister, Region I, were notified on April 16, 1985 that our response would be submitted on or before April 18, 1985.

Should you have any questions concerning the information therein, please contact Mr. Michael W. Laggart at (201)299-2341.

Very truly yours,

Peter B. Fiedler
Vice President and Director
Oyster Creek

PBF/PFC/dam
Attachment

cc: Dr. Thomas E. Murley, Administrator
Region I
U.S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, PA 19406

NRC Resident Inspector
Oyster Creek Nuclear Generating Station
Forked River, NJ 08731

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Violation A

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality such as deficiencies are promptly identified and corrected.

Contrary to the above, measures were not established to promptly evaluate, take corrective actions, and report a condition in which the containment spray heat exchangers pressure was being maintained in a condition contrary to that described in the Facility Description and Safety Analysis Report (containment spray water pressure higher than the emergency service water pressure).

Response

We agree with the Notice of Violation (NOV) in that contrary to the description contained in the Facility Description and Safety Analysis Report, containment spray (CS) pressure was higher than the emergency service water (ESW) pressure, and that this condition was not promptly evaluated, corrected or reported.

The NOV requires us to submit, in accordance with 10CFR2.201 a written statement which includes: (1) the corrective steps which have been taken and the results achieved; (2) corrective steps which will be taken to avoid further violations; and (3) the date when full compliance will be achieved.

Prior to discussing the efforts being taken to improve our system to evaluate, take corrective action, report a condition adverse to safety, we would like to describe the action taken with respect to the technical problem associated with this NOV. Attached is a copy of Licensee Event Report (LER) 84-026 which was submitted on November 20, 1984. This document discussed both the evaluation and acceptability of the existing CS-ESW delta pressure condition, and the future corrective actions we have planned. The LER addresses and satisfies the technical concerns of the negative delta pressure condition regarding dose assessment and as such represents our response to the violation for corrective steps which have been taken and the results achieved. It is important to emphasize that although the dose assessment concluded that doses caused by possible CS heat exchanger leakage is negligible, efforts are continuing to determine and correct the negative delta pressure condition.

In response to the corrective steps which will be taken to avoid further violations, and when full compliance will be achieved, actions are in effect or are being planned, to address that portion of the violation which states that "....measures were not established to promptly evaluate, take corrective action, and report a condition....".

Your letter of March 14, 1985, which transmitted this NOV, requested that we expand our reply to this violation to address the continuing problem of tracking and implementing identified problems. Our response to NRC Region I inspection 84-28, dated March 15, 1985, provided the supplementary information you requested on our commitment tracking system. In that response we stated the tracking system identifies and lists commitments, and provides summary reports to personnel responsible for implementation and to their respective management. It is not, however, a control system which ensures the action will be completed. As would be expected, appropriate

management action; based on information supplied through the tracking system report, is necessary for completion of a commitment. In this instance, the CS-ESW negative delta pressure was tracked as an open NRC unresolved item from 1978. Please note that the tracking system described in procedure LP-002 "Regulatory Correspondence Management and Commitment Control" did not exist during 1978. This item was extracted from the management tracking system in effect during 1978.

The tracking system can be credited in part for the resolution of this item. It was through this system that QA Site Audit S-OC-82-14 identified and issued their Audit Finding Nonconformance which stated "corrective action to evaluate and close out NRC unresolved item 78-19-02 had not been implemented."

In order to assess if NRC concerns are being actively addressed, open NRC items are being compared with those items on our commitment tracking system. Each open item will be evaluated to ascertain if resolutions are properly planned and scheduled. It is our intention to complete this review by August 30, 1985. In conjunction with this review, documentation for completed items is being forwarded to the resident inspectors.

A meeting was held by the Vice President of the Technical Functions division to investigate why corrective action had not been implemented in a timely fashion. During this meeting, the Vice President directed that a sequence of events and formal critique be prepared for this occurrence. The critique will be reviewed to determine if any additional measures should be implemented.

Your cover letter also identified another NRC unresolved item relating to the implementation of the required reactor coolant leakage reduction program and stated that this is an additional example of failure to meet docketed commitments. The item was regarded as complete by the responsible implementing manager, however the inspector pointed out that a portion of the total program was not being implemented. During the exit meeting for inspection 50-219/85-01 this item was discussed and an additional measure of assurance was established. For those NRC committed to or required actions that the licensing action item system considers complete and for which verification cannot be established via the action item system's files, the completed actions would be forwarded to the site Quality Assurance Department for eventual verification.

Violation B

Technical Specification 6.8.1 requires, in part, that written procedures be established, implemented, and maintained. Paragraph 3.8.7.2 of Station Procedure 113, Conduct of Installed Instrument Surveillance, Calibration, and Maintenance, requires that a trip signal be inserted into a channel undergoing surveillance if its sensing instrument is valved out of service for greater than one hour.

Contrary to the above, on January 10, 1985, a reactor water level triple low level sensor was valved out of service for 71 minutes and no trip signal was inserted.

This is a Severity Level IV violation (Supplement I).

Response

We concur with the violation, as stated.

The event which resulted in this violation was reported in detail in Licensee Event Report 50-219/85-001. The primary cause of the event was personnel error, on the part of both control room personnel and instrument technicians. The instrument technicians logged the time out-of-service for the sensor but were not aware of the one hour Technical Specification limit. Control room personnel were aware that the sensor was out of service; however, they did not log the time out-of-service. As a contributing factor, the surveillance procedure used by the instrument technicians did not specifically mention the one hour Technical Specification limit.

The subject Oyster Creek Technical Specification states, "When necessary to conduct tests and calibrations, one channel may be made inoperable for up to one hour per month without tripping its trip system."
We consider the time limitation of this specification too restrictive. A comparison of Oyster Creek Technical Specifications with BWR Standard Technical Specifications (NUREG 0123, Revision 3) was performed and we conclude that the added flexibility for instrument surveillance out-of-service times prescribed by the Standard Technical Specifications are desirable for Oyster Creek.

Standard Technical Specifications allow up to two hours for instrument calibration and surveillance without inserting a trip into a sensor's associated trip system. In addition, there is no per month stipulation as in Oyster Creek Technical Specifications. We feel there is adequate justification to change the applicable Technical Specifications and a request for change will be submitted.

The following corrective steps have been taken:

1. Control room personnel have been instructed to refamiliarize themselves with the protective instrumentation requirements in Technical Specification Table 3.1.1.

2. Control room operators have been instructed to closely monitor instruments having out-of-service time limits during surveillance testing. Times will be tracked by operators as close as practicable. Control room personnel have been directed to ensure the one hour limitation of Technical Specification table 3.1.1 is met, either by returning the instrument to service or having the instrument channel placed in the tripped condition, providing that such action does not cause the total trip function to occur.

3. Lead control room operators have been instructed to log all surveillance tests in the control room log, recording the start time, completion time and test results.

4. An "Equipment-Out-of-Service Sheet" has been added to each applicable surveillance which requires instrument technicians to check out-of-service times prior to the start of surveillance activity.

5. A memorandum concerning the subject of keeping Technical Specification time-limited equipment out-of-service beyond the specified times has been reissued as required reading to instrument technicians and supervisors.

6. The department responsible for performing surveillances is tracking surveillance completion dates to ensure surveillances are not executed twice within a 30 day period if out-of-service times are significant.

7. A copy of the Notice of Violation together with instructional memoranda are currently being distributed to all licensed operators and instrument technicians and their supervisors as required reading.

Corrective steps which will be taken to avoid further violations include the following:

1. Oyster Creek Procedure 116, which administers the conduct of the surveillance program, will be revised to formally incorporate the addition of the "Equipment-Out-of-Service Sheet" to each applicable surveillance.

2. All instrument surveillance test procedures are reviewed against a quality assurance procedure review check list specifically written for surveillance test procedures. The check list requires that the surveillance procedure include documentation of out-of-service and return-to-service times. Existing instrument surveillance procedures have been reviewed to verify that out-of-service and return-to-service times are documented.

   Full compliance has been achieved with the introduction of the "Equipment-Out-of-Service-Sheet." The revision to Procedure 116 is expected to be approved and fully implemented by May 10, 1985.

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oyster Creek, Unit 1	0 5 0 0 0 2 1 9	1 OF 0 7

TITLE (4): Emergency Service Water-Containment Spray Negative Delta Pressure

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
1 1	1 0	7 7	8 4	0 2 6	0 0	1 1	2 0	8 4	--	0 5 0 0 0
										0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9): N
POWER LEVEL (10): 0 0 0

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Paul F. Czaya, Licensing Engineer	AREA CODE 6 0 9 9 7 1 - 4 8 9 3

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

X YES (If yes, complete EXPECTED SUBMISSION DATE) NO

EXPECTED SUBMISSION DATE (15): MONTH 0 6, DAY 3 0, YEAR 8 5

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

Surveillance test results since November 10, 1977 indicate that the delta pressure between the Emergency Service Water (tube side) and Containment Spray (shell side) is negative tube-to-shell in the Containment Spray heat exchangers. This condition is contrary to that described in the Facility Description and Safety Analysis Report. A negative tube-to-shell delta pressure would allow leakage from the Containment Spray (CS) System to enter the Emergency Service Water (ESW) System at the CS heat exchanger and, thence, to the environment. The cause of the negative delta pressure is believed to be a decrease in ESW pump performance and increased pressure drop in ESW piping. Radiological consequences during normal operation and accident conditions have been analyzed and the contribution to offsite dose is considered negligible. Post-LOCA containment heat removal characteristics of the ESW/CS System are not affected. Corrective action will be determined pending the outcome of ongoing ESW System evaluation.

NRC Form 366 (9-83)

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DATE OF OCCURRENCE

The earliest record identifying this condition is a surveillance test data sheet dated November 10, 1977.

IDENTIFICATION OF OCCURRENCE

The Emergency Service Water (ESW) side of the Containment Spray (CS) heat exchangers operates at a lower pressure than the CS side.

This condition is reportable in accordance with 10CFR50.73 (a)(2)(ii)(B).

CONDITIONS PRIOR TO OCCURRENCE

The reactor was in various operating and shutdown modes prior to and subsequent to the identification of this condition.

DESCRIPTION OF OCCURRENCE

The ESW System delivers cooling water to the tube side of the CS heat exchangers from the ultimate heat sink (Barnegat Bay via intake canal). The CS System circulates demineralized water from the pressure suppression chamber (Torus) through the shell side of the CS heat exchangers to the Drywell for post-LOCA containment cooling. Installed delta pressure instrumentation provides indication of tube-to-shell side delta pressure in the CS heat exchangers.

Since November 10, 1977, the tube-to-shell delta pressure has been recorded as less than zero on surveillance test data sheets. This condition is contrary to the system design basis as stated in Section VI-7.2 of the Facility Description and Safety Analysis Report (FDSAR) which states: "Each of the four service water pumps will also have a capacity of about 3000 gpm but will deliver a higher head than the containment spray pump to maintain a higher pressure on the service water side of the heat exchangers so that any leakage will be into the containment side of the heat exchangers." Data resulting from pre-operational testing shows that positive tube-to-shell delta pressure was achieved as designed.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oyster Creek, Unit 1	0 5 0 0 0 2 1 9	8 4	— 0 2 6	— 0 0	0 3 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

APPARENT CAUSE OF OCCURRENCE

The apparent cause of this condition is believed to be gradual degradation of ESW System performance since initial plant operation. Some biofouling found in ESW piping resulting in increased pressure drop in ESW piping coupled with a decrease in ESW pump performance characteristics result in decreased ESW pressure at the CS heat exchangers.

ANALYSIS OF OCCURRENCE AND SAFETY ASSESSMENT

The function of the CS and ESW Systems is to remove heat from the primary containment following a LOCA to control pressure and temperature and maintain them at acceptable levels in order to: 1) reduce the driving force for containment leakage; 2) maintain the structural integrity of containment. The CS/ESW System transfers post-accident decay heat to the ultimate heat sink and provides a physical boundary to the release of post-accident fission products. The CS/ESW System comprises two redundant loops each containing two heat exchangers, two ESW pumps and two CS pumps. The safety function is achieved with operation of one CS pump, one ESW pump and two heat exchangers piped in parallel in one of the two loops.

The consequence of higher CS (shell side) pressure than ESW (tube side) pressure is that should a leak develop in the heat exchanger then Torus water would leak into the ESW System. Radioactive material contained in Torus water would then be discharged to the discharge canal through the leak.

The capability of the CS/ESW System to perform its cooling safety function is not affected by the existing system condition. Adequate cooling water flow is provided by ESW pumps. As determined by calculation the minimum required flow is equal to 2370 gpm. Surveillance testing continually demonstrates ESW flow to be approximately 3000 gpm or greater. Should heat exchanger leakage occur, it will be minimal and will not affect CS cooling effectiveness.

The capability of the CS/ESW System to provide a boundary to the release of post-accident fission products has been affected by the negative tube-to-shell CS heat exchanger delta pressure. Leakage in the heat exchangers will not be contained within the CS System. Leakage can escape the system boundary into the ESW System and, ultimately, to the discharge canal.

An evaluation has been performed to estimate the offsite dose due to leakage from the CS System during a loss of coolant accident (LOCA). The

scenario for this evaluation considers a LOCA has occurred, primary coolant has been introduced into the Torus, and the CS System is initiated. Further, there is a leak in the CS heat exchanger and the pressure in the CS System is higher than in the ESW System thus introducing radioactivity to the environment.

Several assumptions were made and parameters chosen in evaluating this hypothetical leakage and the subsequent offsite dose. The source term utilized was derived from the core inventory given in the Wash-1400 Reactor Safety Study, Appendix 6, Calculation of Reactor Accident Consequences. The figure utilized was $3.98E^8$ curies. This activity was assumed to be all Iodine-131, even though the particulate activity was factored into the source term. Due to the release being unpressurized liquid, no consideration was given to noble gas activity, nor was consideration given to the various phases of iodine activity and their associated characteristics. All of the $3.98E^8$ curies was assumed to enter into the torus and be diluted by Torus water (82,000 cubic feet). This is considered conservative in that all of the activity would not enter into the Torus and the Torus water volume assumed is the minimum level allowed during plant operation. A further measure of conservatism was included in that no credit was taken for water in the CS System piping and heat exchangers. It was assumed that the CS System was in service for one week after the LOCA. The information is further detailed on Table 1 below:

Table 1

Activity Released to Torus (Wash-1400)	$3.98E^8$ Curies
Torus Water Level	82,000 cubic feet $2.32E^9$ ML
Activity of Torus Water	$1.72\ E^5$ uCi/ML
Leak Rate	0.03 gallons/hour $1.9E^4$ ML/week
Total Activity Released	$3.27E^3$ Curies
Dilution (Discharge Canal Flow)	2138.9 cubic feet/second

test, both CS and ESW systems operate simultaneously with one pump operating in each system. One loop is tested at a time. The pumps run for about 15 to 20 minutes, during which time they stabilize and the readings for flow rates and pressures are taken. If a CS heat exchanger develops a leak during testing, leakage to the environment could occur. However, since the duration of the test is very short and the Torus water chemistry and radiation level is on the order of 10^{-4} uCi/ml (liquid isotopic concentrations) the contribution from leakage to offsite releases will be approximately nine orders of magnitude less than the values calculated for the accident scenario, and therefore will be negligible.

CORRECTIVE ACTION

During the recent refueling outage steps were taken to assess the operational condition of the ESW System as follows:

1) An examination of selected portions of ESW piping was performed. Some biofouling was noted near the ESW pumps at the intake structure, but the extent of the biofouling was considered to not have a significant effect on flow rate. ESW piping examined in the turbine and reactor buildings was found to be clean. ESW piping is chlorinated on an intermitent basis to minimize further biofouling.

2) One of the four ESW pumps was refurbished. A minor improvement in performance was noted, however, indicated performance characteristics are still below the design pump curve.

3) As it is felt that current ESW flow instrumentation might provide a conservative indication of actual ESW flow rate, an annubar flow measuring device was installed in one ESW loop to verify the accuracy of portable ultrasonic flow instrumentation. However, problems were encountered in obtaining a reliable measurement with the annubar. Efforts will continue to resolve these hardware problems.

4) Two of four restricting orifices in ESW discharge lines from the CS heat exchangers were examined and found to be in good condition. Their correct sizing was verified.

Further corrective action will be based upon the ongoing evaluation of ESW System performance.

The CS heat exchangers were checked for leaks prior to entering the plant's post-outage startup phase and were found to have no leakage.

the heat exchangers have been leak tested before restart from the recent refueling outage. The criteria for allowable leakage during the test was based on a small fraction of the exposure limits of 10CFR100 as outlined below. The dose evaluation model used in calculating doses is based on normal operations when ingestion of fish and invertibrates is not restricted. However, since dose due to ingestion will not occur during an accident because of the plant controls discussed previously, the only dose factor will be direct shoreline exposure. As noted in Table 1, the leak rate model used a 0.03 gpm CS water leak rate into ESW as being representative of a leak due to galvanic corrosion between the tube and tubesheet from all four heat exchangers. To be more conservative and to specify a leakage criterion that can be accurately measured, a leak rate of 1 gpm was used as the input to the dose calculation. This increases doses by a factor of approximately 2000. Using the 1 gpm leakage and recalculating direct exposure dose the following table results:

Table 2

Offsite Doses Based on CS System Leakage

Scaled to a Leak Rate of 1 gpm

	Direct Shoreline Exposure (Rem)	10CFR100 Limits (Rem)
Whole Body	0.024	25
Thyroid	0.024	300

As stated in "Safety Evaluation of SEP Topic XV-19, Radiological Consequences of a Loss of Coolant Accident", the potential contribution to the LOCA dose of less than 0.1 rem is considered to be negligible. Therefore, it is concluded that the doses caused by CS heat exchanger leakage is negligible. Thus, 1 gpm was the criterion for leakage permitted during the CS heat exchanger leak test although a higner limit could be justified through this same logic. This leak rate limit applies to the total of all four heat exchangers and still provides a factor of 4 margin to what has previously been identified as an insignificant dose. The CS System is the only system operating after a LOCA which has this potential for liquid release to the environment.

The existing condition will not create significant environmental impact during normal operations. The CS heat exchanger is in operation only for surveillance testing during normal operations. Surveillance testing of both the CS and ESW systems is performed once per month. During the surveillance

The information in Table 1 was entered into a dose analysis computer program. This program computes dose for several pathways. The three pathways utilized for the dose calculation were: 1) exposure from shoreline deposition; 2) ingestion of salt water sport fish and; 3) ingestion of salt water invertebrates. These are the most likely pathways of offsite exposure from a spill into the discharge canal. Dose due to each exposure pathway was calculated and then summed for each age group. The program is in accordance with Regulatory Guide 1.109.

As the dose model used considered exposure factors appropriate for evaluations during normal plant operations (per Regulatory Guide 1.109) potential radiation dose values are, therefore, conservative. There was no credit taken for actions which would be performed to limit exposure from the pathways identified. Plant procedures are in effect that specify actions to be taken to minimize offsite dose during an occurrence such as this hypothetical leak. Emergency Plan Implementing Procedure (EPIP) No. 1 will be implemented upon receipt of a high radiation alarm at the discharge of the heat exchanger (ESW side). Since the radiation monitors are area radiation monitoring devices, their indications may not be entirely reliable. However, sampling will also be performed in the discharge canal in accordance with EPIP-11 to determine appropriate actions to minimize exposure to radioactive effluents. These actions would include recommendations to restrict fish and invertebrate ingestion if such protective actions are warranted and the isolation of the leaking containment spray heat exchanger based on ESW radioactivity levels as determined via sampling. Limits of the sampling are based on 10CFR20 limits, which are more conservative than 10CFR100 limits. Notification of civil authorities and the activation of the Environmental Assessment Command Center will be implemented by EPIP-3 and EPIP-35. Protective action recommendations will be made per EPIP-2 to appropriate civil authorities to ensure that actions such as fish/invertibrate ingestion are implemented to ensure that any effect to the health and safety of the public is minimized. These controls are enacted to minimize the ingestion pathway and will occur if radioactivity is detected in the canal. Therefore, including ingestion pathway doses is inappropriate for this evaluation. This is consistent with Regulatory Guide 1.3, which does not include the ingestion pathway doses post-LOCA.

Integral to the evaluation of the acceptability of the present system condition is the integrity of the tube and shell sides of the CS heat exchangers. The original heat exchangers were replaced with ones containing 90-10 copper-nickel alloy tubes during the 1978-79 refueling outage. These tubes developed pinhole leaks in approximately one year and were replaced with titanium tubes in 1980. The heat exchanger presently is constructed of titanium tubes with an aluminum-bronze tube sheet. The corrosion resistance of these materials against sea water is excellent. Therefore, the probability of any gross failure of tubing is small. To ensure against an existing leak,