U. S. NUCLEAR REGULATORY COMMISSION

Report No.	94-09
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License No.	DPR-50
Licensee:	GPU Nuclear Corporation P.O. Box 480 Middletown, PA 17057
Facility:	Three Mile Island Station, Unit 1
Location:	Middletown, Pennsylvania
Inspection Period:	May 17, 1994 - June 27, 1994
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Inspection Summary

The NRC Staff conducted safety inspections of Unit 1 power operations. The inspectors reviewed plant operations, maintenance, engineering, radiological controls, emergency preparedness, and security activities as they related to plant safety.

Results: An overview of inspection results is in the executive summary.

EXECUTIVE SUMMARY

Three Mile Island Nuclear Power Station
Report No. 50-289/94-09

Plant Operations

The plant shutdown on June 1, 1994, and the plant startup and power escalation on June 9, 1994, were well conducted and there was good management oversight. In addition, the reactor coolant drain down to support control rod drive inspections was well controlled. The licensee conducted overall plant operations in a safe and conservative manner.

The licensee's corrective actions were acceptable regarding the imprecise manner they were setting the decay heat river water system throttle valve position. The licensee established a more precise throttle position mark on the valve and intends to normally set the throttle valve position when the flow instrumentation is installed.

Maintenance

The overall conduct of the 'B' emergency diesel generator maintenance was good. The licensee was aggressive in pursuing problems associated with a cracked piston and weakened governor speeder spring.

The licensee's corrective actions were good regarding several instances where Instrumentation and Controls Technicians did not properly return equipment to service following maintenance or surveillance activities. The licensee changed their post-maintenance testing guidelines and surveillance procedures to have an independent verification that equipment is properly returned to service.

The licensee's corrective actions were good regarding an incident where 20 gallons of lubricating oil leaked from the 'B' emergency diesel generator lubricating oil filter cover due to insufficient torquing of the cover bolts. The corrective actions included a review of maintenance and surveillance procedures to ensure that component specific values such as bolt torques are included in the procedure.

Engineering

The licensee shut down the unit to perform control rod drop time testing and found that three rods exceeded the Technical Specification limit. A subsequent inspection of four control rod drive mechanisms (CRDMs) confirmed that the cause of the slow drop times was the hydraulic restriction due to the buildup of reactor coolant precipitates in the CRDM thermal barrier. The NRC is in the process of evaluating the results of the thermal barrier inspection and will review the licensee's corrective actions including the CRDM testing schedule.

Plant Support

A worker who was decontaminating piping failed to meet the Radiation Work Permit protective clothing requirements when she treated an area as decontaminated before it was radiologically surveyed and released by a Radiological Controls Technician. This violation is not being cited because the licensee's efforts in correcting the violation meet the criteria specified in section VII.B the Enforcement Policy.

Overall, the licensee's on-site response during the Annual Emergency Preparedness Exercise was acceptable. However, the approximately one hour delay in recognizing that plant conditions warranted upgrading the emergency classification to an Alert is considered to be a significant weakness.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Licensee Activities

Unit 1 remained at 100% power throughout the inspection period with the exception of May 30 and 31, 1994, when the licensee reduced power to 50% to perform main condenser leak testing and June 1-9, 1994, when the licensee shut down to perform control rod drive testing and inspection.

1.2 NRC Staff Activities

The inspectors assessed the adequacy of licensee activities for reactor safety, safeguards, and radiation protection, by reviewing information on a sampling basis. The inspectors obtained information through actual observation of licensee activities, interviews with licensee personnel, and documentation reviews.

Licensee activities were observed during both normal and backshift hours: 50 hours of direct inspection were conducted on backshift. The times of backshift inspection were adjusted weekly to assure randomness.

2.0 PLANT OPERATIONS (71707, 92700)

2.1 Operational Safety Verification

Overall plant operation was observed and verified that the licensee operated the plant safely and in accordance with procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

--Control Room	--Auxiliary Building
--Switch Gear Areas	--Turbine Building
--Access Control Points	--Intake Structure
--Protected Area Fence Line	--Intermediate Building
--Fuel Handling Building	--Diesel Generator Building

Plant conditions were monitored through control room tours to verify proper alignment of engineered safety features and compliance with Technical Specifications. The inspectors reviewed facility records and logs to determine if entries were accurate and properly identified equipment status or deficiencies. Detailed walkdowns of accessible areas were conducted to inspect major components and systems for leakage, proper alignment, and any general condition that might prevent fulfillment of their safety function.

The inspectors observed the plant shutdown on June 1, 1994, and the plant startup and power escalation on June 9, 1994, and found that overall these evolutions were well conducted and there was good management oversight. In addition, the reactor coolant drain down to support control rod drive inspections was well controlled. The inspector concluded that the licensee conducted overall plant operations in a safe and conservative manner.

2.2 (Closed) Unresolved Item (URI, 50-289/94-07-01) Decay Heat River Water System Throttling

This item concerned the imprecise method the licensee used to set the position of the decay heat river water (DR) system throttle valves, DR-V-3A/B. Once per quarter, the licensee installs flow indication and sets the throttle position of DR-V-3A/B to 8000 gpm per Surveillance Procedure (SP) 1300-3D, "Inservice Test of Decay Heat River Pumps and Valves." However, once per month, DR-V-3A/B are closed to backwash the DR coolers per OPS-S115, "Backwash Decay Heat River Water Coolers." After the backwash, the flow indication is not reinstalled to verify that the valves are repositioned for 8000 gpm. Instead the licensee relied upon 1/2 inch wide black marker lines on the DR-V-3A/B position indicators. On DR-V-3A there were two 1/2 inch lines, 1/2 inch apart.

The license first evaluated what was the acceptable range of DR system flow. The licensee determined that the minimum acceptable flow was 7500 gpm, which is the design basis flow for the DR coolers. The licensee plans further testing to evaluate the maximum acceptable DR system flow. Increasing the DR system flow greater than 8000 gpm could increase the load on the emergency diesel generators beyond an acceptable range.

On June 14, 1994, the inspector observed the licensee perform DR system flow testing. The as-found DR system flow rate was 7950 gpm for train 'A' and 7800 gpm for train 'B'. The licensee removed the old black marker lines and made new lines at 7500 gpm and 8000 gpm. These new lines were 1/4 inch apart. One of the old black marker lines on DR-V-3A, which was faintly visible, extended 1/4 inch below the new 7500 gpm line. It cannot be determined if flow was ever actually set below the design basis flow of 7500 gpm using the old black marker line. To demonstrate the ability to set flow using the new lines the licensee throttled DR-V-3B to 7500 gpm and returned the valve to the 8000 gpm line. The flow indication read 7950 gpm. Based on this repeatability, the inspector determined that using the new line was an acceptable method but not the preferred method of setting flow.

As corrective actions the licensee prepared a training handout to alert operators that the flow rate is very sensitive to valve position. The operators were instructed to minimize the operation of DR-V-3A/B without confirming the flow rate with the flow indicator. The licensee canceled OPS-S115 and will perform the DR cooler backwash in conjunction with SP 1300-3D which specifies installing a flow indicator.

The inspector reviewed the licensee's corrective actions and found them to be acceptable. This item is closed.

3.0 MAINTENANCE (61726, 62703, 71707)

3.1 Maintenance Observations

The inspector reviewed selected maintenance activities to assure that: the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable; required approvals and releases had been obtained prior to commencing work; procedures used for the task were adequate and work was within the skills of the trade; maintenance technicians were properly qualified; radiological and fire prevention controls were adequate; and, equipment was properly tested and returned to service.

Maintenance activities reviewed included:

- Job Order No. 86189, "Disassembly, Assembly, and Inspection of CRDM."
- Corrective Maintenance Procedure 1410-Y-72, "Bolt/Nut Torquing and Sequences."
- General Maintenance Procedure 1405-3.2, "Diesel Engine Maintenance."

The inspector's review of the above maintenance is described in detail in sections 4.1, 3.5, and 3.3.

3.2 Surveillance Observations

The inspectors observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. They verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspectors routinely verified adequate performance of daily surveillance tests including instrument channel checks and reactor coolant system leakage measurement.

Surveillance activities reviewed included:

- Surveillance Procedure 1303-5.2, "Emergency Loading Sequence and High Pressure Injection Logic Channel/Component Test."

- Surveillance Procedure 1301-8.2, "Diesel Generator Annual Inspection (Mechanical)."
- Surveillance Procedure 1303-7.1, "Intermediate Range Channel Test."
- Surveillance Procedure 1302-3.1, "Control Rod Movement."

The overall conduct of Surveillance Procedure 1303-7.1 was good. The other surveillances listed above are described further in sections 3.3, and 4.1.

3.3 Diesel Generator Annual Inspection

From May 16, 1994, to May 21, 1994, the licensee performed the annual inspection of the 'B' emergency diesel generator (EDG) in accordance with Surveillance Procedure 1301-8.2, "Diesel Generator Annual Inspection (Mechanical)." The inspector found that the overall conduct of the maintenance was good.

SP 1301-8.2 requires the licensee to remove and visually inspect the pistons for three cylinders on this Fairbanks Morse, 12 cylinder, opposed piston engine. The licensee selected cylinders 2, 5, and 8 for inspection. The visual examination and dye penetrant test showed that the number 8 cylinder lower piston had a crack approximately 2.2 inches long in the center dome of the piston crown. Magnetic Particle testing on this piston showed four other cracks that were 0.5, 0.75, 0.25, and 0.375 inches. These 6 pistons were last inspected in 1988. The licensee expanded the scope of the inspection to perform magnetic particle and dye penetrant testing on pistons in cylinders 4, 6, and 9, which had last been inspected in 1989. Using dye penetrant and magnetic particle testing, the licensee did not find any cracks on any piston other than the number 8 cylinder lower piston. The remaining 12 pistons that were not removed were inspected using a camera. The licensee replaced the cracked piston with a new piston.

The licensee performed a destructive examination of the removed piston and found that the cracks were caused by thermal fatigue. The cast iron piston crown is 300 mils thick with a 2 mil chromium plating. The 2.2 inch crack in the center of the piston had a depth of approximately 60% of crown thickness. This crack connected to another crack that developed from the back side of the piston. The crack started on the combustion chamber side. Although the cracks extended through the entire crown thickness, the licensee had no prior indications that combustion chamber products were entering the crank case. The other four cracks that were found using magnetic particle testing ranged from 20 to 80 mils deep. In addition, there were many small cracks, approximately 0.6 mils deep in the chromium plating. The licensee plans to further evaluate these results to determine if any corrective actions are necessary.

On May 21, during the diesel post-maintenance run, the load was gradually increased over a 21 hour period. In the last few hours of the run, load was limited to 2.82 MW with the diesel governor speed adjustment against the hard stop. The acceptable range is 2.9 ± 0.1 MW. Load would increase to 2.95 MW by manually lifting the fuel rack lever arm. The licensee shut down the diesel and cleaned the fuel rack. The licensee restarted and successfully loaded the diesel to 3 MW. The licensee questioned whether the additional load capability resulted from the governor cooling off during the maintenance activity.

The licensee contacted a representative from Woodward Controls, the governor manufacturer, who stated that the diesel may have been at the high load limit because the speeder spring may have relaxed over time. [The speeder spring counteracts the force provided when the governor flyweights move outward due to centrifugal force.] The representative stated that when a governor is being refurbished, it is a normal practice to replace the speeder spring if it is older than 5 years. However, speeder spring replacement is not a routine preventive maintenance task.

On May 24, the licensee started and loaded the diesel to 3 MW for 4.5 hours which allowed the governor temperature to stabilize. During the run, the governor load level indicator was near its upper limit (9.8 on a scale of 0-10). Since the speed droop is normally set to zero in its standby condition, the licensee verified that as speed droop was reduced, diesel load increased. The licensee determined that since the diesel was able to carry a 3.0 MW load, the diesel was operable. However, the licensee determined that the governor should not be operating near the upper load limit to achieve 3.0 MW while in parallel operation so on June 20, the licensee replaced the governor on the 'B' EDG. The licensee found that the 'A' EDG was acceptable since the governor load limit indictor was 7.0 at 3.0 MW.

The inspector evaluated whether the weakening of the speeder spring could affect diesel operability when the diesel is running alone. The inspector determined that the licensee's operability evaluation was acceptable because a speed droop setting of zero compresses the speeder spring, placing the governor further from its load limit. In addition, any weakening of the speeder spring over time would be detected during Surveillance Procedure 1303-5.2, "Emergency Loading Sequence and High Pressure Injection Logic Channel/Component Test," when generator frequency is recorded when the diesel is started at 900 rpm and the speed droop is set at zero.

The inspector concluded that the overall conduct of the diesel maintenance was good. In addition, the inspector determined that the licensee was aggressive in pursuing the cracked piston and governor speeder spring problems.

3.4 (Closed) Unresolved Item (URI, 50-289/93-13-01) Return of Equipment to Service

This issue involved several instances where Instrumentation & Controls (I&C) technicians did not properly return equipment to service following maintenance or surveillance activities. Between September 1992 and July 1993, the licensee and inspector found many instances where safety related and non-safety related equipment were not in the correct alignment. The instances involving safety related equipment included: 1) The redundant once-through-steam-generator level instruments were selected for input into the integrated control system rather than the ones specified in the operations surveillance procedure. Alone, this incident had minimal safety significance since the redundant instrumentation could perform the same function. 2) The reactor building atmosphere radiation monitor was rendered inoperable due a valve left out of position during a quarterly surveillance. Alone, this incident had minimal safety significance since diverse methods of detecting a reactor coolant system leak were available. 3) The valves in the air supply to the steam pressure controller for the turbine driven emergency feedwater pump were out of position. Alone, this incident had minimal safety significance since the steam pressure controller was not rendered inoperable. 4) A building spray system flow instrument equalizer valve was found partially open, causing the instrument to read low. Alone, the safety significance of this incident is minimal since the building spray system would have still performed its safety function. 5) When troubleshooting the makeup system valve that controls pressurizer level, the instrument air supply pressure was found to be adjusted to 30 psi rather than 60 psi. Alone, the safety significance of this incident was minimal because this did not result in any significant plant upsets; and 6) A function selector switch on the 'B' post accident hydrogen monitor was found out of position. Alone the safety significance of this incident was minimal since the hydrogen monitor was not rendered inoperable. Although these events individually had minimal safety significance, collectively the failure to properly return safety related equipment to service could have significant safety implications. The unresolved item concerned a review by the licensee to determine if a programmatic weakness exists.

The licensee prepared Plant Experience Report 93-002 to evaluate this weakness. The licensee looked collectively at all the events and found no common root cause. In each case, there were different panel locations, various I&C personnel, various supervision, various operations support, and various work shifts. Although there was no common root cause, the licensee has performed the following corrective actions: 1) To cover maintenance activities, Administrative Procedure (AP) 1071, "Post-Maintenance Testing Guidelines," now states that instrument tasks where valve manipulation is required, requires verification of proper indication of operating equipment or independent verification of valve lineup of idle equipment. 2) For surveillance activities, the licensee developed a list of 18 surveillances that did not perform a final check of valve and switch positions that were manipulated during the surveillance. The licensee has nearly completed adding this final check to these procedures.

The inspector determined that the licensee's corrective actions are adequate to prevent recurrence of similar incidents. Enforcement for the individual examples was determined in prior NRC reports. Since no programmatic weakness was identified this issue was determined not to represent a violation of NRC requirements. This item is closed.

3.5 (Closed) Violation (VIO, 50-289/93-14-01) Emergency Diesel Generator Lubricating Oil Leak

This item involved a July 1, 1993, incident where 20 gallons of lubricating oil leaked from the 'B' emergency diesel generator (EDG) lubricating oil filter cover due to insufficient torquing of the cover bolts. The licensee estimated that the lubricating oil level would have fallen to a critical level after 3.5 hours. The licensee determined that there were four causes for the event: 1) Surveillance Procedure (SP) 1301-8.2, "Emergency Diesel Generator Annual Inspection," did not specify the torque value for the lubricating oil filter housing cover bolts; 2) The procedure biennial review checklist did not indicate that torque values should be included in the job-specific procedures; 3) The process to be used to obtain data concerning unspecified torque values was not followed; and 4) Management's expectation of what information vendor representatives can supply and can be acted on without challenge was not clear to the maintenance technician.

As corrective actions, the licensee changed SP 1301-8.2, and General Maintenance Procedure 1405-3.2, "Diesel Engine Maintenance," to specify a lubricating oil filter cover bolt torque of 120 $\pm$ 5 ft-lbs. The licensee also changed the checklist in Administrative Procedure (AP) 1001K, "Biennial Procedure Review," to check to ensure appropriate quantitative requirements such as torque values and clearances are included. Out of a sampling of 42 procedures that have received the biennial review, one procedure, Operating Procedure 1102-11, "Plant Cooldown," was changed to specify a quantitative value. The inspector did not find any examples where a specific value should have been specified but was not. Using these new guidelines of AP 1001K, the licensee committed to complete a biennial procedure review of all safety related procedures by December 1995. The licensee also changed AP 1070, "TMI-1 Maintenance Plan," to state that the intended scope of vendor representative guidance is primarily of a qualitative nature (the best way to take a measurement, troubleshooting suggestions, etc.). If the quantitative measurement is missing, personnel should obtain the value from the vendor manual, applicable procedure such as Corrective Maintenance Procedure 1410-Y-72, "Bolt/Nut Torquing and Sequences," or through Plant Engineering.

The inspector concluded that the licensee's corrective actions are adequate to prevent recurrence. This item is closed.

4.0 ENGINEERING (71707, 92703, 40500)

4.1 Control Rod Drop Times (Closed, LER 94-004-00, Control Rod Drop Times Exceed Technical Specification Limits)

In accordance with Confirmatory Action Letter 1-94-004, on June 1, 1994, the licensee shut down to test control rod drop times. The testing was being performed as a followup to trip times exceeding the Technical Specification (TS) 4.7.1 limit of 1.66 seconds that occurred on March 17, 1994. On June 1, three rods, 1-3, 4-5, and 6-5 with times of 2.07, 2.01 and 2.2

seconds respectively, exceeded the 1.66 second limit. These three rods were among the 12 rods that exceeded the limit in March 1994, and two of the three had exceeded the limit on October 14, 1993, during the 10R refueling outage. To confirm the suspected root cause of the slow drop times, the licensee decided to inspect the thermal barrier on the three rods with slow times on June 1, as well as rod 3-6, which had slow times in March 1994 and October 1993. The suspected cause of the slow drop times was that reactor coolant precipitate (crud) deposits had developed in the control drop drive mechanism (CRDM) thermal barrier checks valve and guide bushing. When the control rod is tripped, the check valves allow reactor coolant system (RCS) coolant to flow into the upper area of the CRDM, filling the space that the control rod lead screw had occupied. If the crud causes the check valves to stick closed, the restricted hydraulic flow of water causes the rod motion to be slowed following a trip.

4.1.1 Thermal Barrier Inspection

The licensee inspected the removed thermal barriers and their ball check valves and found dark crud deposits had accumulated. All four thermal barrier check valves were stuck closed on rods 1-3, 3-6 and 4-5. On rod 6-5, three valves were stuck and one valve was initially free but the licensee later found that this valve would stick when the ball was rotated to a certain position. Since the estimated opening force on the ball during a reactor trip would only be 0.05 pounds, the licensee considered the ball stuck if there was any noticeable resistance in moving the ball.

The crud deposits ranged from loose granular deposits that could be wiped off to hard tightly adherent deposits. The loose mud-like crud deposits tended to harden as they dried. There were deposits on the balls as well as the cavities housing the balls. It did not appear that the balls were stuck to the valve seat but rather the balls were hampered or prevented from movement by irregular, tightly adherent deposits on the ball and ball channel. The licensee plans to have the crud deposits analyzed in a laboratory.

The licensee measured the inside diameter of the guide bushing on each thermal barrier. The lead screw guide bushing had uneven, hard deposits on the guide bushing surface. Assuming a maximum design bushing inner diameter of 1.540 inches, the crud buildup on the bushing ranged from 0.003 inches to 0.009 inches thick. The lead screw diameter on rods ranged from 1.507 inches to 1.510 inches, indicating there was little or no deposit buildup.

4.1.2 Licensee Evaluation of Thermal Barrier Inspection Results

The Plant Review Group (PRG) reviewed the inspection results and determined that these results confirm the previously suspected root cause of the slow drop times which are: 1) The low pH in the coolant in the CRDM causes the corrosion products dissolved in the coolant to be less soluble that they would be if pH were in the desired range of 6.9 or higher; and 2) the thermal barrier design is not tolerant of deposits. Corrosion products deposited in the thermal barrier region prevent the check valve from opening. The deposits that adhered to the ball and the cavity prevented the ball from lifting when the deposit thickness exceeded the clearance dimension. The crud reduced the clearance between the thermal barrier bushing and lead screw which caused the drop times to exceed the time expected for all four thermal barrier check valves stuck with nominal guide bushing clearance (2.10 seconds). The licensee did not consider the loose granular crud deposits above the ball to be a likely failure mode.

The licensee determined that the low pH in the system resulted from one or more of the following: 1) The CRDM was filled with borated water (2530 ppm) with little lithium (0.4 ppm) when the RCS was filled following refueling outages. [The cycle 10 boron concentration at criticality was 2449 ppm, and after four effective full power days was 1851 ppm.] 2) Trip testing the CRDM at the beginning of the cycle with refueling boron concentration (2540 ppm) and low lithium (0.4 ppm). 3) After the outage in November 1993, to replace the pressurizer relief valve, the RCS was refilled with a boron concentration of 2400 ppm and lithium was about 2 ppm. 4) At the beginning of Cycle 10, the at-temperature RCS pH was 6.8 when the desired range is 6.9 or greater; and 5) Prior to the 10R refueling outage, pH was reduced to induce an RCS crud burst so that the crud could be filtered to reduce outage radiation dose.

The transition in temperature across the thermal barrier could contribute to the deposits. Some deposits that may be soluble in the 600° F coolant below the barrier may become insoluble in the 240° F coolant in the CRDM.

There is a definitive correlation between drop time and the radial location of the CRDM. The CRDMs in the periphery of the core have longer drop times. This may be due to temperature or flow patterns. The CRDMs in the periphery of the core are farther from the RCS due to the domed shape of the reactor vessel head. The additional distance could result in a lower temperature at the thermal barrier causing insolubility of corrosion products. The licensee could not explain why ten of the twelve rods that have failed are on one half of the core.

B&W calculated that four stuck ball valves would result in a rod drop time of 2.10 seconds and three stuck valves would result in a rod drop time of 1.46 seconds assuming nominal guide bushing clearance. However, rod 3-6 had a drop time of 1.3 seconds with all four valves stuck and rod 6-5 had a drop time of 2.20 seconds with only three valves stuck. Both of these rods had trip times that were in-specification, out-specification, and back in-specification after successive trips in March 1994. The licensee concluded that the conditions had changed between the drop time test and the inspection, since no other explanation could be offered.

The deposits are not limited to the specific control rods that have experienced drop times in excess of the Technical Specification limit since the drop times on the in-specification rods are above the times expected if all check valves were clear. The uneven deposits on the check valve surfaces make it possible for other check valves to stick. The licensee determined that the RCS cooldown and draining has the potential to affect ball check freedom, but would not adversely affect bushing clearance, since the rod movement surveillance tends to mechanically clear or clean the guide bushing. The drop times on rods 1-3, 4-5 and 6-5, since the March 1994 test, indicate that the bushing clearances have improved.

When comparing the as-found test results, 12 rods exceeded the drop time specification in March 1994, while only three rod exceeded the specification on June 1. The drop times of the three rods which failed were faster than the March 1994 test. The as-found average drop time of the 49 in-specification rods on March 1994 was faster on June 1 (1.363 seconds versus 1.337 seconds). The licensee determined that there is a potential for drop times for some rods to exceed the Technical Specification after a period of operation, but that the measures that are in effect will limit the drop time to less than three seconds. B&W had performed an analysis that was approved by the licensee, which showed that with all 61 rods at 3.0 seconds drop time, the safety analysis requirements would still be met. The licensee determined that the safety consequences for the June 1 event are minimal since the acceptance criteria for all accidents are met with the as-found drop times. If additional rods were to degrade due to ball reorientation, the rods would still be expected to meet the safety analysis requirement of 3.0 seconds.

4.1.3 Corrective Actions

The licensee replaced the thermal barriers for rods 1-3, 4-5, 3-6 and 6-5 with new thermal barriers having larger clearances in the ball check valves in accordance with Job Order No. 86189, "Disassembly, Assembly, and Inspection of CRDM." The old thermal barrier, a Royal Industries Type A, which has a ball diameter of 0.5625 inches and a ball channel inner diameter of 0.591, was replaced with a new thermal barrier, a Diamond Power Modified Type A, which has the same ball diameter but has a channel inner diameter of 0.6875 inches. The post-maintenance drop times on rods 1-3, 3-6, 4-5, and 6-5 were 1.312, 1.328, 1.320, and 1.296, respectively.

As discussed in Inspection Report 50-289/94-07, the licensee increased the RCS lithium limit from 2.2 ppm to 2.65 ppm to allow an increase in RCS pH to 6.9 to reduce the rate of corrosion and increase crud solubility. The licensee added lithium to the RCS prior to the RCS fill on June 7, 1994, to assure that the pH of the coolant in the CRDM was within the desired range. The licensee plans to continue to exercise the control rods every two weeks using a 30 second insertion time to aid in reducing the deposit buildup in the gap between the lead screw and the thermal barrier bushing. The licensee has connected the 25% zone reference switch to the plant computer to allow checking rod drop times in the event of a reactor trip. The licensee is working with the B&W owners group to develop joint long term solutions to this problem. By September, the licensee plans to provide a long term plan to address necessary actions to improve CRDM performance and reliability.

4.1.4 Conclusion

The inspector reviewed Licensee Event Report (LER) 94-004-00 concerning the slow control rod drop times on June 1, 1994, and found the LER to be acceptable. The NRC is reviewing the results of the thermal barrier inspection and will evaluate the licensee's corrective actions, including the CRDM testing schedule.

5.0 PLANT SUPPORT (71707, 82301, 82302)

5.1 Radiological Controls

The inspectors examined work in progress to verify proper implementation of health physics procedures and controls. The inspectors monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspectors observed personnel working in RWP areas and verified compliance with RWP requirements. During routine tours, the inspectors verified a sampling of high radiation area doors to be locked as required. The inspector had one concern which is described in the following section.

5.1.1 Failure to Meet Radiation Work Permit Requirements

On June 6, 1994, during a tour of the Auxiliary Building, the inspector noted that a Radiological Waste Operator was reaching over a contaminated area boundary to decontaminate piping. The operator was wearing only cotton glove liners for protective clothing when Radiation Work Permit (RWP) #037323 required wearing cotton gloves, rubber gloves, and a lab coat. The operator then performed a swipe of the piping and exited the area to survey the swipe and found no contamination. The operator stated she was wearing just the cotton liners for protective clothing because she had cleaned the area and did not expect any loose surface contamination.

The inspector discussed the incident with the Manager of Chemistry and Radiological Waste who stated that the Radiological Waste Operators are required to meet the RWP requirements for [illegible]a until the area has been surveyed and released by a Radiological Controls [illegible]n. As a corrective action, the licensee is preparing a memorandum that will be [illegible]d with Radiological Waste Operators that discusses this incident. The inspector determined that this corrective action was adequate to prevent recurrence.

The failure of the Radiological Waste Operator to meet the RWP requirements is a violation of Radiological Controls Procedure 6610-ADM-4110.04, "Radiation Work Permit," which requires the individual to comply with the radiological control requirements specified for the work to be performed as outlined within the RWP. The safety significance of this incident is minimal since it did not result in the spread of contamination. This violation is not being cited because the licensee's effort in correcting the violation met the criteria specified in section VII.B of the Enforcement Policy, dated January 1, 1994.

5.2 Security

The inspectors monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspectors observed security staffing, operation of the Central and Secondary Alarm Stations, and licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, protected area access control and badging procedures were observed. In addition, protected and vital area barriers, compensatory measures, and escort procedures were routinely inspected.

The inspectors concluded that the Security Plan was being properly implemented.

5.3 Annual Emergency Preparedness Exercise (Closed, Inspector Followup Items 50-289/93-10-01 through 93-10-09)

The licensee conducted a partial-participation exercise on May 19, 1994. The NRC inspection included a scenario review, observation of exercise activities, discussions with the licensee staff, and a review of selected records. Prior to the exercise the inspector reviewed the drill scenario and determined that overall, the final scenario adequately tested the major portions of the Three Mile Island Nuclear Station Emergency Plan and Implementing Procedures.

5.3.1 Exercise Performance

In the Emergency Control Center (ECC) [Simulator Control Room and Radiological Assessment Center (RAC)], operators quickly identified the primary-to-secondary leak by observing the increasing main condenser offgas radiation monitor readings. Operators accurately estimated the initial leak rate within seven minutes of the radiation monitoring system alarm.

The following expected actions were done well:

- The Shift Supervisor promptly and correctly declared an Unusual Event based on a primary-to-secondary leak of greater than one gpm but less than 50 gpm and assumed the duties of Emergency Director (ED).

- At approximately 50% power the operators secured the 'B' main feedwater pump, which stopped the release path via the 'B' auxiliary condenser offgas. Later in the scenario, when the steam driven emergency feedwater pump started, the operators secured it to stop the release path.

- Operators started the Reactor Building charcoal filter fan which recirculates Reactor Building air and they secured the Reactor Building purge fans to help minimize the release out the open purge valves.

- The overall use of the Abnormal Transient Procedures was good.

- The turnovers from the Shift Supervisor Emergency Director (ED) to the augmented ED and from the augmented ED to the Emergency Support Director (ESD) were thorough.

- The Radiological Assessment Center (RAC) promptly sent a technician to perform radiological surveys to determine which once-through-steam generator had developed the simulated primary-to-secondary leak and to assess the changing radiological conditions in the Intermediate building and Turbine Building.

- The licensee dispatched a radiological field monitoring team in the direction of the plume within 30 minutes of declaration of the Unusual Event.

- When the primary-to-secondary leak increased, the ED immediately noted that the subcooling margin dropped below 25°F and was aware that this condition required the declaration of a Site Area Emergency.

- While in the Site Area Emergency the ED thoroughly reviewed the protective action recommendation logic diagram in preparation for a General Emergency.

- The Operations Support Facility (OSF) repair team assigned to conduct electrical repairs to close the Reactor Building inner purge valve performed well and there was good support by the Technical Support Center (TSC) engineer at the work site.

The following was identified as an exercise weakness:

- The licensee initially failed to recognize that the high range condenser offgas radiation monitor for gaseous activity, RM-A-5 HI Gaseous, was greater than the high alarm setpoint, which is a condition which requires the licensee to declare an Alert. The Operations Coordinator (Plant Operations Director) noted the condition and the licensee declared an Alert approximately one hour after receiving the radiation monitor alarm.

The following were identified as areas for potential improvement:

- There were several instances where ECC communications to other facilities could be improved. For example, the ECC and the Emergency Offsite Facility (EOF) were aware that in addition to the primary-to-secondary leak, there were indications of reactor coolant leaking into the Reactor Building [there was a simulated main steam line leak in the affected OTSG]. However, the OSF and TSC were not aware of the reactor coolant leak. Though the OSF and TSC actions were still correct in attempting to close the open Reactor Building purge valves, the work crews should have known to expect the high radiation levels at the purge valves.

- At the start of the drill, the computer on the Shift Supervisor's desk displayed a recently installed screen that is designed to provide radiological assessment information from the RAC. The screen is a good licensee initiative because it provides up-to-date radiological information to the ED. However, this screen was not functional in the actual Control Room. The concern is that Control Room personnel would become accustomed to using equipment during drills that would not be available during an actual event. The emergency preparedness personnel thought the screen was functional in the Control Room as of April 25, 1994, but on May 20, 1994, the inspector found that the screen was not functional. The Shift Supervisor at the simulator was aware that the screen would not be available in the actual Control Room and therefore, he would have to use the RAC computer. However, discussions with other licensee personnel indicated that they thought the computer screen was available in the Control Room. The licensee did not make the screen functional until June 15, 1994.

- The OSF repair team assigned to perform mechanical repairs to close the Reactor Building outer purge valve did not have the procedures, technical manuals or drawings at the work site. Although this information was being reviewed at the OSF and although the individuals were very familiar with the purge valve, the information should also be at the work site to assist in their troubleshooting efforts.

5.3.2 Licensee Critique

The inspectors attended the licensee's exercise critique on May 20, 1994. After a brief review of the scenario scope, the licensee's lead Drill Controllers presented their observations. Overall, the licensee's critique was acceptable and most NRC findings were noted.

5.3.3 Followup of the 1993 Annual Exercise Findings

Inspector Follow Item 50-289/93-10-01 - This item involved a licensee observer prompting the Radiological Assessment Coordinator (RAC) by instructing him on dose assessment computer start-up and providing input data. The licensee counseled the individual and reviewed this issue with the Drill Observers/Controllers prior to the 1994 Annual Exercise. The inspector did not observe any Drill Observer/Controller prompts during the 1994 Annual Exercise. This item is closed.

Inspector Follow Item 50-289/93-10-02 - The RAC used the wrong iodine spiking factor, which incorrectly resulted in a Site Area Emergency recommendation, although no premature event declaration was made. The licensee found that the On-Shift RAC was not familiar with the operation of the computer hardware and software regarding the iodine spiking factors.

As corrective action, the licensee initially provided training for the individual involved and provided training to all RAC personnel during their normally scheduled training. In addition, the licensee has made changes to the computer software to automatically provide the correct iodine spiking factor, which should eliminate the errors associated with the manual input. This item is closed.

Inspector Follow Item 50-289/93-10-03 - This issue involved the Emergency Director (Shift Supervisor) calling out the entire Emergency Response Organization (ERO) at the Unusual Event. The licensee's procedures provide this option. However, it is not a normal practice to call out the entire ERO at the Unusual Event. The concern was that this aspect of exercise performance may be developing into a practice that unnecessarily differs from the practice for an actual event. The licensee evaluated the inspector's concern but still contended that portions or all of the ERO can and should be called out early based on the ED's discretion. The licensee determined that the current minimum callout requirements are still appropriate. The licensee plans to address specific instances where callouts in excess of the minimum were inappropriate, as they occur. During the 1994 exercise the licensee again called out the entire ERO at the Unusual Event. The licensee determined that this decision was appropriate since there was a release in progress via the main condenser offgas. The inspector determined that the licensee's decision for the callout was not an automatic ED decision. The decision was well thought out, was fully discussed with licensee management on the telephone and had a sound basis. The inspector determined that the licensee's approach was acceptable and this item is closed.

Inspector Follow Item 50-289/93-10-04 - This issue involved the fact that it was unclear whether the ECC or the TSC had the lead in determining the OTSG leak rate for use in release dosage rate calculations. The TSC personnel believed they were responsible, but did not question when the announced leak rates differed from the TSC calculations. The licensee determined that the TSC had the lead responsibility for the leak rate calculations and that the TSC calculations were being used by the RAC. The RAC periodically used the Shift Technical Advisor calculations to confirm the TSC values, which accounted for the discrepancy in leak rate values. The licensee has included this issue in the lessons learned portion of the emergency preparedness training program. This item is closed.

Inspector Follow Item 50-289/93-10-05 - This issue involved the TSC Observer prompting the TSC Coordinator regarding which core flood system check valve had failed. The licensee counseled the individual and reviewed this issue with the Drill Observers/Controllers prior to the 1994 Annual Exercise. The inspectors did not observe any Drill Observer/Controller prompts during the 1994 Annual Exercise. This item is closed.

Inspector Follow Item 50-289/93-10-06 - Communications between the TSC and the ECC regarding the priorities and which equipment problems had already been fixed was considered to be an area of potential improvement. As a corrective action the licensee reminded communicators of the importance of prompt communications. As described above, the inspector noted this area continues to be an area for potential improvement. This item from the 1993 Annual Exercise is closed and this area will be inspected again during future exercises.

Inspector Follow Item 50-289/93-10-07 - This issue involved the TSC evaluating which temperature or pressure indicators should be used to determine when to shift to decay heat removal for core cooling. Such information could already have been proceduralized. As a corrective action, the licensee changed Abnormal Transient Procedure 1210-05, "Once-Through-Steam-Generator Tube Leakage," which states that decay heat removal may be initiated at an incore temperature of 300°F. The inspector found this corrective action acceptable and this item is closed.

Inspector Follow Item 50-289/93-10-08 - This item concerned the fact that some portable battery powered lamps in the EOF had weak batteries. The licensee found that these lamps were not considered emergency lighting and therefore were not periodically checked. The licensee has removed these lamps from the EOF. The licensee has installed two permanent battery powered lamps that are continuously charged which will automatically turn on when facility power is lost. The inspector found the licensee's corrective action acceptable and this item is closed.

Inspector Follow Item 50-289/93-10-09 - This item involved the lack of careful preparation and review of press releases which could degrade the licensee's credibility during an actual event. As a corrective action, the licensee is now providing an additional level of review for accuracy prior to issuing the press release. The inspector found that the overall quality of press releases during the 1994 Annual Exercise was good. This item is closed.

5.3.4 Conclusion

The inspector concluded that overall, the licensee's on-site response to the exercise scenario was acceptable. However, one of the primary objectives of an exercise is for the licensee to demonstrate the ability of control room personnel to recognize (by plant simulator indications) that emergency action levels have been reached or exceeded, properly classify the emergency, and implement the emergency plan. The one hour delay in recognizing the high main condenser offgas readings and declaring an Alert is considered to be a significant weakness.

6.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting with licensee management summarizing inspection activities and findings for this report period. Licensee comments concerning the issues in this report were documented in the applicable report section. No proprietary information was identified as being included in the report.