U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	94-07
Docket No.	50-289
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:	April 5, 1994 - May 16, 1994
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Approved by: John F. Rogge, Chief, Reactor Projects Section No. 4B — 5/27/94 Date

Inspection Summary

The NRC Staff conducted safety inspections of Unit 1 power operations. The inspectors reviewed plant operations, maintenance, engineering, radiological controls, 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. 50-289/94-07

Plant Operations

The licensee conducted overall plant operations in a safe and conservative manner.

The licensee's strike contingency plan was comprehensive and provided for a sufficient number of licensed operators and qualified support personnel to safely operate the plant.

The licensee's procedures and training were inconsistent with regards to whether the steam supply to the turbine driven emergency feedwater pump should be depressurized prior to resetting the overspeed trip mechanism. It was inconclusive whether the resultant differential pressure across the trip valve could have delayed resetting the overspeed trip mechanism. The licensee agreed to change the procedures and training to depressurize the steam line.

Due to an isolated operator error, a Control Room Operator aligned the wrong emergency diesel generator (EDG) which resulted in both EDGs being inoperable for less than one minute. The licensee plans to provide training on this incident to operating personnel.

The method the licensee uses to set the position of the decay heat river water system throttle valves was considered to be imprecise. During monthly testing, the throttle valves are closed and then repositioned to the throttle setting by use of black marker lines. The black marker lines on the 'A' train throttle valve position indicator covered 16° out of the 90° of butterfly travel. The adequacy of this method of setting the position of the valves is considered an unresolved issue pending evaluation and testing by the licensee.

The high pressure injection (HPI) system was found to be properly configured per the plant's procedures. The licensee's efforts in evaluating HPI pump vibration were good and their planned trending program for inservice testing was a positive initiative. In addition, the Reliability Centered Maintenance program for the HPI system was considered a strength in that it was comprehensive and effective in improving the preventive maintenance and inservice testing for the HPI system.

Maintenance

There was good procedure usage and good supervisory oversight during the 'A' emergency diesel generator inspection.

Engineering

Thus far, the licensee has adequately met their commitments of Confirmatory Action Letter 1-94-004 regarding excessive Cycle 10 control rod drop times.

TABLE OF CONTENTS

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Licensee Activities

Unit 1 remained at 100% power throughout the inspection period.

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.

The inspectors observed licensee activities during both normal and backshift hours: 37 hours of direct inspection were conducted on backshift. The times of backshift inspection were adjusted weekly to assure randomness.

2.0 PLANT OPERATIONS (71707, 92709)

2.1 Operational Safety Verification

The inspectors observed overall plant operation and verified that the licensee operated the plant safely and in accordance with procedures and regulatory requirements. The inspectors conducted regular tours of the following plant areas:

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

The inspectors observed plant conditions 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 identified equipment status or deficiencies. The inspectors conducted detailed walkdowns of accessible areas to inspect major components and systems for leakage, proper alignment, and any general condition that might prevent fulfillment of their safety function.

The inspector concluded that the licensee conducted overall plant operations in a safe and conservative manner.

2.2 Engineered Safety Feature System Walkdown - High Pressure Injection System

The inspector verified the operability of the high pressure injection (HPI) system for its emergency standby mode by performing a detailed walkdown of the accessible portions of the system. The inspector reviewed the appropriate sections of the Updated Final Safety Analysis Report (UFSAR), Design Basis Document (DBD), Operating Procedure (OP) 1104-2, "Make-up and Purification System," quarterly Surveillance Procedure (SP) 1300-3H, "In-service Testing (IST) of Make-up Pumps and Valves," and Drawing No. 302-661, "Make-up and Purification System Flow Diagram." The inspector, with the assistance of a Control Room Operator (CRO), performed a valve line-up of the HPI system using OP 1104-2, Enclosure I, "Start-up Valve Checklist." The inspector confirmed that the HPI components and system, both mechanical and electrical, were in the required emergency standby alignment; instrumentation was valved in; as-built prints reflected the as-built system; and the overall conditions observed were satisfactory.

The inspector reviewed SP 1300-3H and noted the licensee only required operators to observe the stroking of one of the four HPI injection valves, MU-V-16A. The licensee stated the reason the SP specified observing MU-V-16A was the valve's yoke bushing failed in September 1991 during diagnostic valve testing (see Inspection Report 50-289/91-23, Section 5.2). The yoke bushing failed after 17 years operation due to inadequate stem lubrication. The licensee also found severe degradation of the yoke bushings for the other three injection valves and replaced the bushings. The inspector questioned why the SP did not require the inspection of the other three injection valves, MU-V-16B/C/D, since they experienced the same degradation. The licensee stated that the reason they only required the observation of MU-V-16A was: 1) the valve's yoke bushings took 17 years to fail with no stem lubrication and are not likely to wear at an excessive rate now that the stems are lubricated; 2) the yoke bushing in MU-V-16A is likely to experience the most rapid degradation because the valve is installed at an angle and the weight of the valve operator causes a slight stem deflection; 3) MU-V-16B/C/D are also in a high radiation area and would submit personnel to unnecessary exposure; and 4) the licensee observes the stroking of MU-V-16A/B/C/D during the performance of Preventive Maintenance Procedure E-13, "Limitorque Valve Operator Inspection." Based on this the inspector determined that the observation of only MU-V-16A was acceptable.

The inspector reviewed the IST data associated with the HPI pumps since 1988 and found that all the data for each HPI pump was in the acceptable range. The last IST data showed that the vibration on HPI pumps A/B/C was 0.55 mil, 0.8 mil, and 0.32 mil respectively. The acceptable range for vibration is 0-1 mil. Historically, the licensee has experienced a higher vibration on the 'B' HPI pump compared to the others. The engineering staff performed an evaluation of the 'B' HPI pump's performance and determined that cavitation vibration and pump imbalance were primarily responsible for the pump's high vibration. The 'B' HPI pump normally operates at 150 gpm to provide makeup flow and seal injection water to the reactor coolant pumps. The design flow rate for the HPI pumps is 300 gpm at 2400 psi. The lower flow rate causes swirling action at the eye of the first stage impeller which erodes the impeller and causes pump imbalance. When the licensee begins a new 10 year ISI program in September 1994, and pump performance will have to meet the new requirements of ASME/ANSI OM Part 6, 1987. These requirements state that for pump vibration above 0.525 inches per second, the testing frequency shall be doubled and at 0.7 inches per second, the pump will be declared inoperable. Previous data on all three HPI pumps shows that vibrations will occasionally exceed 0.525 inches per second but remain below 0.7 inches per second. The licensee is pursuing material changes for the 'B' HPI pump first stage impeller and plans to install balancing weights to the rotating assembly to minimize the vibration. In addition, the licensee plans to ask the NRC for a relief request because they determined that these 6800 rpm HPI pumps inherently have had higher vibrations and this has not affected pump reliability.

The inspector discussed with the Manager Plant Material Assessment the licensee's Reliability-Centered Maintenance (RCM) program for the HPI system. The RCM program involves evaluating the function a system performs, determining the plausible failures of these system functions, and identifying critical components that are necessary to perform these functions through a failure mode and effect analysis. The licensee then evaluated the adequacy of the associated preventive maintenance tasks and inservice testing to attempt to identify and prevent the failure of these critical components. Occasionally, the licensee chose to delete preventive maintenance tasks on components that they determined were not critical and instead plans to operate these components until failure. For example, the licensee chose to delete the PM to periodically calibrate the local lubricating oil pressure indication for the HPI pumps and instead relies on operators to identify when the accuracy of the indication may be in question. The lubricating oil pump starting circuit pressure switches, which are critical components, will continue to be calibrated. The RCM for the HPI system confirmed that existing PMs and testing were adequate in the vast majority of the cases. The licensee added several new preventive maintenance tasks for the HPI system including lubricating oil ferrography for the HPI pumps and speed changer. In addition, the licensee corrected the preventive maintenance procedure for the differential pressure transmitter that measures seal injection flow, MU-42-DPT. The licensee had found that MU-42-DPT was not receiving the necessary preventive maintenance because the electronic indicator in the control room and the local pressure gauge in the makeup valve alley had the same tag identification numbers. The inspector determined that the RCM program on the HPI system was comprehensive and was effective in improving the HPI system preventive maintenance and inservice testing.

The inspector noted that the licensee trends IST data for the HPI system but does not have a formal program. The IST coordinator keeps a notebook where he records IST data for comparison against past data. The licensee's system engineers are developing a computer based formal performance trending program where IST data collected during surveillance testing can be tracked to predict future performance of a critical component. The licensee plans to have this program fully implemented by the end of 1994.

The inspector concluded that the HPI system was properly configured per the plant's procedures and the licensee's efforts in evaluating HPI pump vibration were good. In addition, the licensee's planned IST trending program was a positive initiative and the RCM program on the HPI system was considered a strength.

2.3 Emergency Feedwater Pump Trip Reset

The inspector reviewed the Incident Investigation Team report on the 1985 Davis-Besse loss of emergency feedwater (EFW) incident to determine if the procedures and training at TMI have the same weaknesses. During the Davis-Besse incident, the operators initially could not reset the EFW pump turbine trip mechanism because the differential pressure across the trip throttle valve inhibited valve movement. The Shift Foreman was able to reset the trip throttle valve using a pry bar but the correct method was to isolate and depressurize the steam supply line. Although the Davis-Besse trip valve was a gate valve and the TMI trip valve is a butterfly valve, the inspector questioned whether the licensee at TMI would also have difficulty opening the trip valve under a differential pressure. Even though the force to turn the butterfly valve is balanced, the force against the valve stem may create sufficient friction to make opening the valve difficult.

The inspector reviewed the licensee's procedures and found that they were inconsistent on whether the steam supply line should be depressurized. TMI Abnormal Transient Procedure 1210-10, "Abnormal Transients Rules, Guides and Graphs," step 2.4, "Actions for Failure of the Emergency Feedwater System," specifies closing the steam supply valves, MS-V-13A/B, but does not specify opening steam supply line drain valve, MS-V-52, to relieve steam supply line pressure. However, Surveillance Procedure 1300-3G, "Inservice Test of EF-P-1 and Valves," step 8.1.15, has a Caution, "DO NOT attempt to reset EF-U-1 with the steam chest pressurized. Damage to the trip valve bushings and stem may result." Operating Procedure (OP) 1106-6, "Emergency Feedwater System," step 8, has a similarly worded Caution. The inspector questioned the Operations Engineer who had added the Cautions to the procedure, but he did not specifically recall what prompted the addition. The Operations Engineer believes the Cautions were either from the vendor manual or that they had difficulty resetting the trip lever in the past. The inspector reviewed the procedure change that added the Caution to OP 1106-6 but it did not mention why the Caution was added.

The Worthington vendor manual for EP-P-1A specifies isolating the steam supply and opening a drain valve connected to the valve body to relieve steam pressure prior to resetting the trip mechanism. The vendor manual provides a drawing of two trip valve designs, one a globe valve and the other a butterfly valve. On the globe valve drawing there is a note stating to relieve pressure prior to resetting the trip valve. The butterfly valve drawing does not have this note. There is only one set of instructions for resetting the trip mechanism, which specifies opening the drain valve, but does not indicate that the instructions are only applicable to the globe valve design. Only the globe valve has a "drain valve connected to the valve body," but other than that, the drawing part numbers that are in the trip reset instructions are applicable to both drawings. (Since the butterfly valve does not have a "drain valve connected to the valve body", a steam supply line drain valve such as MS-V-52 would be used for relieving pressure.) Since the vendor manual is unclear whether the steam pressure should be relieved with the butterfly valve design, the licensee agreed to contact the vendor. The vendor has not made the butterfly valve design for a number of years and the vendor representative did not have any direct experience with operating the butterfly valve under a differential pressure. The vendor representative believed that opening the drain valve was necessary to reset the globe valve design but was also a good practice for the butterfly valve design.

The inspector reviewed the licensee's EFW training and found that this training was inconsistent regarding isolating and depressurizing the steam supply line. The EFW lesson plan and Job Performance Measure (JPM) 11.2.05.33, "Reset Emergency Feedwater Pump Overspeed Trip Lever," specify isolating but not depressurizing the steam supply line. However, the Training Department provides a handout to Auxiliary Operators (AOs) that provides the answers to all the training objective questions in the EFW lesson plan. One of the training objective questions involves how to reset the trip mechanism. In the answer provided, the licensee specifies isolating the supply line and then depressurizing it via the drain valve, MS-V-52.

The inspector interviewed eight AOs to determine their understanding regarding depressurizing the steam supply line before resetting the trip mechanism. One AO out of the eight did not know that opening the drain valve may be necessary to reset the trip mechanism.

The inspector reviewed the licensee's response to SOER 86-01, an industry report that described the Davis-Besse loss of emergency feedwater incident. The SOER recommended providing training to operators on resetting the overspeed trip but did not specifically recommend depressurizing the steam line. Since the licensee now provides hands on training to operators on resetting the overspeed trip, the inspector determined that the licensee adequately addressed the SOER recommendation.

The inspector discussed his concern with the licensee and they agreed to add the depressurization of the steam supply line to ATP 1210-10 and Alarm Response Procedure J-1-2, "EFW Pump Overspeed Trip." In addition, the licensee agreed to change the EFW training lesson plan and Job Performance Measure 11.2.05.33.

The inspector concluded that the licensee's procedures and training were inconsistent with regards to whether the steam supply to the turbine driven emergency feedwater pump should be depressurized prior to resetting the overspeed trip mechanism. The inspector determined that it was inconclusive whether the resultant differential pressure across the trip valve could have delayed resetting the overspeed trip mechanism. The licensee's corrective actions of changing the procedures and training to depressurize the steam line were acceptable.

2.4 Both Emergency Diesel Generators Out-of-Service

On May 15, 1994, the licensee prepared to start the 'B' emergency diesel generator (EDG) prior to removing the diesel from service for the annual diesel overhaul and inspection. When the Control Room Operator (CRO) performed the switch alignment for the diesel run in accordance with Surveillance Procedure 1303-4.16, "Emergency Power System," he mistakenly performed the alignment on the 'A' EDG rather than the 'B' EDG. The CRO placed the 'A' EDG exciter switch from automatic to manual, the starting switch from automatic to manual, and the voltage regulator from 46% to zero. This alignment prevents an automatic start of the diesel. The CRO who performed the alignment acknowledged the "Diesel Generator 1A Blocked" alarm. When the CRO instructed the Auxiliary Operator at the diesel to trip the fuel racks in accordance with the procedure (verifies the proper operation of the overspeed alarm), he correctly tripped them on the 'B' EDG, resulting in a "Diesel Generator 1B Blocked" alarm. The Shift Supervisor and CRO immediately recognized the condition and within one minute restored the 'A' EDG to its standby condition. Technical Specifications (TS) were not violated since, TS 3.7.2.c requires that if two diesels are inoperable, the plant shall be placed in hot shutdown within 12 hours.

The licensee evaluated if this incident was reportable per 50.73 (a)(2)(v) as a condition that alone could have prevented the fulfillment of a safety function. The licensee determined that this incident was not reportable based on the following: 1) The condition was immediately recognized at the time of occurrence and was corrected; and 2) During the daily TS required testing of the 'A' EDG while the 'B' EDG is undergoing maintenance, the 'A' EDG is not in its standby condition. The inspector reviewed NUREG 1022, Supplement No. 1, "Licensee Event Report System," questions 7.10 and 7.11, which indicate that this incident is not reportable since the resulting system configuration is not prohibited by plant TS. Therefore, the inspector agrees with the licensee that this incident is not reportable since they did not violate the TS.

The inspector reviewed SP 1303-4.16 and agrees with the licensee that this incident was not caused by an unclear procedure. The CRO involved stated that he had no other duties other than the 'B' EDG run. The CRO had confirmed twice with management that he was to operate the 'B' EDG but simply made an error.

The Operations Director stated that he plans to review this incident with all operating crews as an example where the 'Be Sure' program principals could have prevented this error. The inspector determined that this was an isolated incident and the licensee's planned corrective action was acceptable.

2.5 Potential Strike of Union Employees

The inspector reviewed the licensee's strike contingency plan to assess the licensee's ability to safely operate the plant without union personnel. On May 1, 1994, the contract for local International Brotherhood of Electrical Workers Union (IBEW) with the Metropolitan Edison

Company expired. On May 16, 1994, the union voted to approve the new contract which will expire on April 30, 1997. Prior to this approval, the union and the company had been extending the old contract on a day to day basis. IBEW represents about 400 plant workers which includes licensed Control Room Operators, Auxiliary Operators, maintenance technicians, and other non-supervisory plant personnel. The union does not represent Senior Reactor Operators (SROs) or plant staff engineers. The licensee had developed contingency plans for continued power operation using SROs and other supervisory personnel had the union decided to strike.

The inspector concluded that the licensee's strike contingency plan was comprehensive and provided for a sufficient number of licensed operators and qualified support personnel to safely operate the plant.

2.6 Decay Heat River Water System Throttling (UNR 50-289/94-07-01)

During a plant tour, the inspector noted a black marker line on the position indicator for the decay heat river cooler discharge valves, DR-V-3A/B. DR-V-3A/B are butterfly valves that are used to throttle decay heat river water flow. The inspector questioned how the licensee set the throttle position on these valves since the black marker line on DR-V-3B was 1/2" wide and on DR-V-3A, there were two 1/2" wide marker lines, 1/2" inch apart.

Once per quarter,the licensee performs Surveillance Procedure (SP) 1300-3D, "Inservice Test of Decay Heat River Pump and Valves." The DR system has flow detectors, DR-FI-289A/B, but they are normally disconnected and capped off because debris in the river water would soon enter the instrument. SP 1300-3D specifies installing the flow indicator and adjusts the throttle position of DR-V-3A/B as necessary to obtain 8000 gpm. Following the surveillance, DR-V-3A/B remains in the throttled position and the flow indicator is disconnected. Once per month, the licensee performs OPS-S115, "Backwash Decay Heat River Coolers," which references Operating Procedure (OP) 1104-32, Decay Heat River Water System," to perform the backwash. Since backwashing redirects decay heat river flow through the coolers in the reverse direction, DR-V-3A/B must be closed. OP 1104-32, section 3.3.2, which provides instructions for the backwashing, states "Note the number of turns open and then close DR-V-3A" (train B is backwashed in the following section using similar wording). The inspector questioned plant operators who stated that the way they note the number of turns open is using the black marker. After the backwash DR-V-3A/B is returned to the as found position. Later in the procedure the DR-V-3A/B is independently verified to be "Open to the 'As Found' Position (8000 gpm)." OP 1104-32 does not specify installing DR-FI-289A/B to measure 8000 gpm.

The inspector had the following concerns with the manner OP 1104-32 specifies setting and verifying the throttled position of DR-V-3A/B: 1) Once DR-V-3A/B have been throttled, there is no flow indication to verify that it has been performed correctly; 2) The Final Safety Analysis Report (FSAR) gives a design basis flow rate of 7500 gpm for the decay heat river water cooler and 7900 gpm for the decay heat river water pumps. The licensee's accident analysis assumes 7500 gpm flow. Although it is unclear whether there must be 7500 gpm or 7900 gpm to meet the design basis, the wide black markers provide a very imprecise method of throttling to 8000 gpm, especially since there is no range given; 3) The operator who did not see the initial position of the valve, such as the person who independently verifies the position of DR-V-3A/B to 8000 gpm, is a an even greater disadvantage; and 4) The black markers lines for DR-V-3A cover approximately 16° out of the total of 90° valve travel. The licensee did not have a throttling characteristics curve for this valve to show the change in flow for 16° of travel starting at approximately 40° open. The inspector also noted that on the startup of the decay heat river system per OP 1104-32, step 1, the position specified for DR-V-3A/B is "Throttled to 8000 gpm." Again, the flow instrument is not installed to verify the proper flow rate.

The inspector discussed these concerns with the licensee and they agreed to evaluate: 1) What is the design basis flow rate, 7500 gpm or 7900 gpm?; 2) What is the acceptable range of flow that DC-V-3A/B can be throttled to and is the position indicator precise enough to set this throttle position using an official permanent marker that they would install?; and 3) Is it necessary to backwash the coolers once per month or can it be performed in conjunction with the quarterly inservice test that installs the flow indicator since there is normally no flow through the coolers? Also, the licensee determined that installing the flow indicator now to verify sufficient flow was not necessary, because operations personnel who had repositioned the valves in the past were confident the valves were positioned properly. The licensee plans to check the as-found flow when they perform the quarterly inservice test in June, 1994.

Since the method the licensee is using to set the throttled position of DR-V-3A/B is considered to be imprecise, it is possible that flow through the coolers would be less than the design basis flow. This issue will remain unresolved until the licensee completes their evaluation and performs decay heat river water flow testing in June, 1994 **(50-289/94-07-01).**

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. 084318, "Diesel Generator 'A' Protective Relays."

- Job Order No. 085402, "Disassemble and Clean Solenoid Valve Body," for EG-V-16AA."

- Job Order No. 084638, "Diesel Generator Annual Inspection."

- Job Order No. 086889, "Inspect Air Start Distributor and Springs."

The inspector found that the overall conduct of the above emergency diesel generator maintenance was good. The inspector found that the maintenance was conducted in accordance with the approved procedures and there was good supervisory oversight.

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. The inspectors 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 1303-3.1, "Control Rod Movement."

- Surveillance Procedure 1300-3G, "Inservice Test of EF-P-1 and Valves."

- Surveillance Procedure 1300-3H, "In-service Testing (IST) of Make-up Pumps and Valves."

- Surveillance Procedure 1303-4.16, "Emergency Power System."

- Surveillance Procedure 1300-3D, "Inservice Test of Decay Heat River Pump and Valves."

The above surveillances are discussed in Sections 2.2. 2.3, 2.4, 2.6 and 4.1.

4.0 ENGINEERING (92703, 40500)

4.1 Followup of Confirmatory Action Letter 1-94-004 Regarding Cycle 10 Control Rod Drop Times (Closed, LER 94-002-00, Control Rod Drop Times Exceed Technical Specification Limits)

During control rod drop time testing on March 17 and 18, 1994, the drop times for 12 control rods exceeded the 1.66 second limit specified in Technical Specification (TS) 4.7.1. On March 25, 1994, the licensee met with NRC management to discuss the basis for startup and continued operation of TMI-1. Following the meeting, the NRC communicated to the licensee certain commitments that if agreed to, would constitute acceptable justification for startup and operation of TMI-1. In a letter from the licensee dated March 26, 1994, the licensee submitted a formal basis for resuming power operation. In Confirmatory Action Letter 1-94-004 dated March 29, 1994, the NRC found the licensee's commitments specified in their March 26, 1994, letter were acceptable. The inspector reviewed the licensee commitments specified in CAL 1-94-004 that have been completed to determine if the licensee fulfilled those commitments.

The licensee made several commitments regarding short-term corrective actions to minimize crud buildup within the control rod drive mechanism (CRDM). The licensee committed to increase the lithium concentration in the reactor coolant system (RCS) to raise pH to reduce the rate of corrosion. The inspector reviewed the Safety Evaluation associated with the change to SP-1101-28-001 which involved changing the reactor coolant system specification for lithium. The lithium-boron control that the licensee plans to implement for the remainder of Cycle 10 is to establish pH at 6.9 (at core average temperature), without exceeding 2.65 ppm lithium. The licensee then plans to maintain the pH at 6.9 until lithium decreases to approximately 2.2 ppm. Then, the licensee plans to maintain lithium at approximately 2.2 ppm until pH increases into the desired range, 6.9 to 7.4. The inspector reviewed the licensee's chemistry results and found that the licensee has maintained pH at approximately 6.9 after the startup on March 26, 1994. Lithium concentration following the startup was initially at 2.6 ppm and has slowly decreased as boron depleted and the current band is 2.05 ppm to 2.35 ppm. The lithium control band for the previous Cycle 9 was 1.9 ppm to 2.2 ppm.

The licensee committed to exercise the CRDMs every two weeks during the remainder of Cycle 10 to reduce the likelihood of crud buildup in the gap between the lead screw and the thermal barrier bushing. The licensee performed Surveillance Procedure 1303-3.1, "Control Rod Movement," on April 8 and 21 and May 5, 1994. The licensee changed SP 1303-3.1 to insert the control rods for 30 seconds versus 4 seconds to promote better interchange of RCS water inside the thermal barrier bushing. The inspector observed the performance of SP 1303-3.1 on April 8 and 21 and noted that the plant transient caused by the 30 second insertion was minimal. On April 8, group 5 rods caused the largest transient; reactor power decreased to 91%, RCS pressure decreased from 2155 psi to 2105 psi, the average RCS temperature decreased from 578°F to 576°F, and axial power imbalance changed from -4.82 to -8.41.

The licensee committed to obtain control rod drop times within three months of reactor startup (March 26, 1994). The licensee plans to shut down on June 1, 1994, to perform control rod drop time testing. The licensee committed to submit their evaluation criteria and a contingency plan to be utilized for this control rod drop time test. On April 22, 1994, the licensee submitted their evaluation criteria for the testing and their contingency plan. On May 3, 1994, there was a meeting between the NRC and the licensee to discuss the licensee contingency plan. The NRC is reviewing the licensee proposal for acceptability.

The inspector reviewed Licensee Event Report 94-002-00, associated with the excessive rod insertion times and found that the corrective actions in the LER are consistent with the licensee commitments in CAL 1-94-004. Therefore, LER 94-002-00 is closed. The inspector concluded that, thus far, the licensee has met the commitments as discussed above for CAL 1-94-004.

5.0 PLANT SUPPORT (71707)

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 determined that overall radiological controls practices were properly implemented.

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, the inspectors observed protected area access control and badging procedures. In addition, the inspectors routinely inspected protected and vital area barriers, compensatory measures, and escort procedures.

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

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.