U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report No.	50-289/90-20 50-320/90-11	License:	DPR-50 DPR-73

Licensee: GPU Nuclear Corporation
P. O. Box 480
Middletown, Pennsylvania 17057

Facility: Three Mile Island Nuclear Station, Units 1 and 2

Location: Middletown, Pennsylvania

Dates: October 30, 1990 - December 3, 1990

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Reactor Projects Section No. 4B

Inspection Summary: Combined Inspection Report Nos. 50-289/90-20 and 50-320/90-11 for October 30, 1990 - December 3, 1990.

Areas Inspected: The NRC staff conducted routine and reactive safety inspections of Unit 1 power operations and Unit 2 cleanup activities. The inspectors reviewed plant operations, maintenance and surveillance, radiological practices, security measures and engineering support activities as they related to plant safety. Licensee action on previous inspection findings was also reviewed.

Results: An overview of inspection findings are summarized in the executive summary of this report.

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*Denotes NRC inspection procedures used to inspect the area identified

Executive Summary

I. PLANT OPERATIONS

Overall, Unit 1 plant operations were conducted in a safe manner. On November 28, 1990, power was reduced to 75 percent to repair tube leaks in the tenth stage feedwater heater.

On November 29, 1990, the licensee started the evaporation of Accident Generated Water (AGW) at TMI-2 after the Commonwealth of Pennsylvania lifted a temporary hold following the completion of their review of the Susser-Hatch Cancer Study. However, evaporation was stopped on December 1, 1990, when the evaporator compressor seized. No AGW has been released to the environment. The compressor repairs are ongoing.

II. RADIOLOGICAL CONTROLS

Routine observations of radiological controls were conducted throughout the inspection period. No noteworthy observations were made.

III. MAINTENANCE AND SURVEILLANCE

The licensee continues to conduct maintenance and surveillance activities in a safe and timely fashion. No noteworthy observations were made.

IV. ENGINEERING AND TECHNICAL SUPPORT

Engineering support to plant activities was appropriate to resolve specific plant problems. In general, good engineering interface with the plant staff continues to be noted.

V. EMERGENCY PREPAREDNESS (EP)

Routine review of this area identified no noteworthy observations.

VI. SECURITY

Routine review of this area identified no noteworthy observations.

VII. SAFETY ASSESSMENT AND QUALITY VERIFICATION

The safety evaluation associated with the TMI-1 Asiatic Clam Chemical Treatment indicated that this evolution did not have the potential to adversely affect nuclear safety. The inspectors concluded that the licensee's procedures should have required a more thorough review of the issue.

Momentary voltage changes to a Reactor Protection System power supply were found. The power supply was replaced. The licensee's evaluation did not fully address the appropriate safety issues.

DETAILS

1.0 Summary of Facility Activities

1.1 Licensee Activities

The licensee began the inspection period with TMI-1 operating at 95 percent power. Reactor power slowly decreased over the inspection period to 94 percent due to the gradual fouling of the secondary side of the steam generators which reduced heat transfer. On November 28, 1990, the licensee reduced power to 75 percent to repair a leak in the tenth stage feedwater heater. The repair work was still in progress at the conclusion of the inspection period.

On November 29, 1990, the licensee started the evaporation of Accident Generated Water (AGW) at TMI-2 after the Commonwealth of Pennsylvania lifted a temporary hold following the completion of their review of the Susser-Hatch Cancer Study. However, this evaporation process was secured on December 1, 1990, when the evaporator compressor seized. No AGW had been released to the environment.

1.2 NRC Staff Activities

This inspection assessed the adequacy of licensee activities for reactor safety, safeguards and radiation protection. The inspectors made this assessment by reviewing information on a sampling basis, through actual observation of licensee activities, interviews with licensee personnel, or independent calculation and selective review of applicable documents. Inspections were accomplished on both normal and back shift hours.

NRC staff inspections were generally conducted in accordance with NRC Inspection Procedures (NIPs). These NIPs are noted under the appropriate section in the Table of Contents to this report.

1.3 Persons Contacted

D. Atherholt, Operations Engineer
*G. Broughton, Operations/Maintenance Director
*J. Byrne, Manager, TMI-2 Licensing
G. Giangi, Manager, Corp. Emergency Preparedness
R. Harper, Manager, Plant Material
C. Hartman, Manager, Plant Engineering
D. Hassler, Licensing Engineer
*H. Hukill, Vice President and Director
G. Kuehn, Site Operations Director, TMI-2
R. Knight, Licensing Engineer
*M. Nelson, Manager, Safety Review
J. Paules, Senior Operations Engineer
*R. Rogan, Director, Licensing and Nuclear Safety

M. Ross, Plant Operations Director
T. Seaver, QA Auditor
*H. Shipman, Manager, Plant Engineering
E. Schrull, Licensing Engineer
G. Simonetti, Manager Emergency Preparedness
*R. Skillman, Director, Plant Engineering
P. Snyder, Manager, Plant Material Assessment
*C. Smyth, Manager, TMI-1 Licensing
J. Stacy, Manager, Security
R. Wells, Licensing Engineer
*H. Wilson, TSS/ISI Coordinator

* Denotes attendance at final exit meeting (see Section 8.0)

2.0 Plant Operations

2.1 Operational Safety Verification

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

--Control Room	--Control Building
--Auxiliary Building	--Diesel Generator Building
--Switchgear Area	--Yard Areas
--Access Control Points	--Containment Penetration Area
--Protected Area Fence Line	
--Fuel Handling	--Turbine Building

During the inspection, operators were interviewed concerning knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for observed activities. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspector comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was verified. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted leads control log. The inspector also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards.

No noteworthy observations were made.

2.2 Followup of Events Occurring During the Inspection Period

During the inspection period, the inspectors provided onsite coverage and followup of the following evolutions.

2.2.1 Power Reduction to Repair Feedwater Heater

On November 28, 1990, reactor power was reduced to 75 percent to repair tube leaks in the "B" tenth stage feedwater heater. The leak in the feedwater heater was discovered on November 25, 1990 when a high condensate flow alarm was received. The bypass on the feedwater heater level control valve was initially used to maintain water level. The feedwater heater was then isolated and removed from service and a slow and orderly power reduction occurred.

Initial inspections of the feedwater heater indicated several tubes had failed. Removal of these tubes from service was in progress at the end of the period. The licensee is also still in the process of evaluating the heater's condition to determine the appropriate repair. The heater was expected to be returned to service the week of December 4, 1990.

The inspector reviewed the licensed operator's response to the feedwater transient and concluded timely and appropriate actions were taken by the operating crew.

2.2.2 Commencement of Accident Generated Water Evaporation

On November 29, 1990, the licensee began the evaporation of AGW at Three Mile Island - Unit 2, after the Commonwealth of Pennsylvania lifted a temporary hold. This hold was requested in September to allow the Commonwealth time to study a paper published by the American Journal of Epidemiology entitled, "Cancer Near the Three Mile Island Nuclear Plant: Radiation Emissions," commonly referred to as the Sutter-Hatch Cancer Study.

The evaporation is a two step process. AGW is first boiled to separate the water from entrained contaminates and then recondensed. This condensed water can be vaporized and released to the environment (coupled mode) or sent to a holding tank for later vaporization (uncoupled mode).

The final operational check and initial operation of the evaporator was in the uncoupled mode using domestic water. The evaporator was then operated in the uncoupled mode using AGW. Approximately 15,000 gallons of the condensate was to be collected and sampled to ensure the decontamination factor was within specification. This water was then to be vaporized. However, on December 2, 1990, the evaporator compressor seized. Operation of the evaporation portion of the system was immediately secured. The licensee is still evaluating the cause of the failure. Because the failure occurred prior to producing 15,000 gallons of condensate, the licensee never released any AGW to the environment.

The licensee's repair and restart of evaporation will be reviewed during subsequent inspections. The inspector had no other questions.

3.0 Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation Work Permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent) and personnel frisking were observed on a sampling basis.

No noteworthy observation were made.

4.0 Maintenance and Surveillance Observations

4.1 Maintenance Observation

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;

-- activities were accomplished by qualified personnel;

-- where necessary, radiological and fire preventive controls were adequate and implemented;

-- QC hold points were established where required and observed;

-- functional testing was performed prior to declaring the particular component(s) operable.

-- equipment was verified to be properly returned to service.

Maintenance activities reviewed included:

-- Preventative Maintenance Procedure IC-125, Integrated Control System Observation. Inspected on November 29, 1990.

-- Preventative Maintenance Procedure IC-49, Reactor Building Purge Valve AH-V-A and 1D. Inspected on November 29, 1990.

-- Job Order No. 00031657 Clean EF-V-30 ABCD Hand/Auto Switches. Inspected November 30, 1990.

-- Corrective Maintenance Procedure 1410-T-1, Condensate Storage Tank Internal Inspection. Inspected November 13, 1990.

-- Job Order No. 33395 Replacement of "A" RPS cabinet power supply Inspected on November 30, 1990.

In general, maintenance activities were conducted in a safe manner.

4.2 Routine Surveillance Observation

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, Technical Specifications were satisfied, testing was performed by qualified personnel and test results satisfied acceptance criteria or were properly dispositioned. The following surveillance testing activities were reviewed:

-- Surveillance Procedure 1301-5.8, rev 13, Station Storage Battery Monthly. Inspected November 1, 1990.

-- Surveillance Procedure 1302-3.2, rev 54, Radiation Monitoring System Calibration. Inspected October 31, 1990.

-- Surveillance Procedure 1303-4.1, rev 68, Reactor Protection System. Inspected October 31, 1990.

-- Surveillance Procedure 1303-4.15A, rev 11, Radiation Monitoring System Monthly Test-Atmospheric Channels. Inspected October 31, 1990.

No noteworthy observations were made.

5.0 Security

5.1 Routine Security Evaluations

Implementation of the Physical Security Plan was observed in the following plant areas:

-- Protected Area and Vital Area barriers were well maintained and not compromised;

-- Isolation zones were clear;

-- Personnel and vehicles entering and packages being delivered to the Protected Area were properly searched and access control was in accordance with approved licensee procedures;

-- Persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were authorized;

-- Security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and

-- Adequate illumination was maintained.

No deficiencies were identified.

6.0 Safety Assessment and Quality Verification

6.1 TMI-1 Asiatic Clam Chemical Treatment

On November 14, 1990, the licensee contracted with a vendor to perform a chemical treatment to kill clams in the Unit 1 pump house intake bay and the TMI-1 river water and fire service systems. This treatment was performed to keep the clam population from causing a flow blockage of service water to safety related systems. Flushing of the services systems was performed by special test procedure (STP 1-90-0054, TMI-1 Asiatic Clam Chemical Treatment).

The inspector reviewed and witnessed portions of the STP. Review of selected valve lineups and restoration of affected systems to normal configuration demonstrated that proper control was maintained of plant systems.

The safety determination is the first step in the licensee's safety evaluation process which determines whether the second step, a safety evaluation, must be performed. The Safety Determination Form determines whether a document has any potential to adversely impact nuclear safety or plant operations; involves a Technical Specification and/or FSAR change; involves an Unreviewed Safety question and/or; involves any potential environmental impact.

The inspector also reviewed the safety determination written for the STP indicating that this evolution did not have the potential to adversely affect nuclear safety. A technical review was performed to determine that the current clam population was not sufficient enough in size or quantity to cause heat exchange fouling. The safety determination should have indicated that this evolution could have affected nuclear safety to ensure that the extent of this technical review was adequate. The inspector believes that a preliminary technical review should not have governed the information in the safety determination, rather, the safety evaluation should have decided the extent of technical review.

Overall, in spite of the possible misuse of the safety determination, the appropriate review was performed and the work completed satisfactorily.

6.2 Reactor Protection System Voltage Fluctuations

The inspector attended the licensee's plant review group (PRG) meeting associated with determining the operability of the "A" Reactor Protection System (RPS) power supply. The licensee had indications that a power fluctuation/degradation was occurring in the power supply. A 300 millivolt reduction in the normal 15 VDC power was noted on several occasions. Based on the ability of the power supply to perform its intended function, the licensee considered the power supply operable. The licensee's review, however, did not establish a voltage level at which the power supply should be considered inoperable. The licensee is still in the process of attempting to establish this value. The licensee elected to replace the power supply and perform further evaluations on the removed power supply to determine the cause of the degradation. To ensure that the problem is isolated to the "A" RPS power supply, the licensee is monitoring the other three RPS channel power supplies.

The inspector reviewed the licensee actions in response to the degradation in the power supply. Based on discussions with licensee engineers and information presented at the PRG meeting, the inspector concluded that the licensee had not been able to fully characterize the effect that the power supply fluctuations would have on RPS setpoints. The lack of detailed information caused a significant reliance on instrument and control engineers' understanding of the system to determine the effects caused by the degraded power supply. The inspector considered this a weakness in the licensee's evaluation/determination of the operability of this power supply. In general, however, the inspector did not disagree with the licensee's overall conclusion on this issue. The inspector will follow this issue during future routine inspections.

7.0 Follow-up of Previous Inspection Findings

The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspector were subsequently reviewed through discussions with licensee personnel, documentation reviews and field inspection to determine whether licensee actions specified in the OIs had been satisfactorily completed. The overall status of previously identified inspection findings was reviewed, and planned/completed licensee actions were discussed for the items reported below.

7.1 (Closed) Unresolved Item (50-289/86-03-08): Appendix R Circuit Breaker Coordination Review for Non-safety Loads and Unresolved Item (50-289/87-06-09): Electrical/I&C Analyses for Heat Sink Protection System.

As a condition of restart at TMI-1 in 1985, the Commission directed the staff to conduct two Performance Appraisal Team (PAT) inspections. The first of these PAT inspections was reported in Inspection Report 50-289/86-03 and identified, among other issues, a concern with overcurrent protection and coordination of components within the electrical distribution system. Part of this concern was that the associated circuit review performed to satisfy 10 CFR 50, Appendix R "may not have included the effect of the remaining load on a bus while comparing the breaker or fuse curves of the feeder with those of the largest circuit load." The licensee performed additional reviews of this area and, in response to the original evaluation, replaced a 500 ampere circuit breaker with one having a smaller rating. By letter dated December 23, 1986, the licensee committed to perform a rigorous electrical analysis of auxiliary electrical systems including a fault current study and an interrupting device coordination study of all potential associated circuits. This analysis was intended to resolve the Appendix R concern related to safety-related and non safety-related circuits associated by common enclosure as discussed in NRC Generic Letter No. 81-12.

The staff was informed by a letter from the licensee dated March 20, 1987, that the fault study and coordination study had been completed. Several computer runs using the DAPPER program were made to determine the maximum short circuit current possible under the most stringent operating conditions. A total of 49 coordination curves were drawn using the CAPTOR program to verify proper coordination of fault/overload interrupting devices. Cable size and corresponding circuit breaker/fuse ratings were also reviewed for all power circuits supplied from the 6.9kV, 4.16kV, 480 volt switchgear and from the motor control centers and distribution panels. These studies were performed by Gilbert Commonwealth, Inc., the architect/engineer for TMI-1, and were documented in Report No. G/C 2734 dated November 20, 1987. The report contained 31 findings and 17 recommendations. The staff performed a cursory review of the preliminary report in March 1987 (See Inspection Report No. 50-289/87-09) prior to startup from the 6R refueling outage. The report was referred to staff specialists for more detailed review.

The staff has completed its review of the Gilbert Commonwealth report and of the limited actions taken by the licensee in response to the report. Specific follow-up inspection activity has not taken place to track licensee response to all report recommendations. Staff activity to date has concentrated on the thoroughness of the studies and the report and on the potential

Appendix R implications of the findings. Follow-up actions will be inspected in the near future.

The staff concluded that the subject report was very thorough and detailed and adequately achieves its intended purpose. One of the most significant findings of the short circuit fault current study was that the available current, assuming very conservative initial conditions at the 6900 volt and 4160 volt buses, could exceed the interrupting and momentary ratings of the respective circuit breakers. The initial conditions assumed that (a) all 230kV lines are in service, (b) one of the two auxiliary transformers is out of service, (c) the main TMI-1 turbine generator is operating at maximum load (2785MVA), (d) one of the emergency diesel generators (EDGs) is being load tested (3750KVA) and (e) all normal motors plus all engineered safeguard (ES) motors are operating. With these conditions, the 6900 volt breakers could experience 42,000 amps compared to their interrupting rating of 40,000 amps and the 4160 volt breakers could experience 52,000 amps compared to their interrupting rating of 49,000 amps. A second computer run was made assuming an EDG was not being load tested and showed that, in this case, the breaker ratings were not exceeded. In its March 20, 1987 letter, the licensee committed to restrict load testing (via plant operating procedures) of the EDG's during power operations with a single auxiliary transformer. This procedure restriction has been verified by the staff.

The short circuit study also showed that short circuit currents at the 1C and 1J 480 volt switchgear could exceed the short time rating of certain associated circuit breakers. The staff has reviewed a licensee evaluation (3300-89-0023) dated February 24, 1989, that justifies not installing current limiters, as originally planned, in one of these circuits. The evaluation notes that the probability of the assumed initial conditions simultaneous with a bolted fault is extremely low. For example, operation with a single auxiliary transformer has occurred for only one hour during the 52,000 hours of plant power operation. The staff also notes that having the main generator at rated output is mutually exclusive of having all ES motors operating. Therefore, both conditions could not exist simultaneously. The staff finds the licensee's action on this issue acceptable.

The short circuit study also determined that short circuit current at the ES 480 volt control center could exceed the bus bar bracing rating of 22,000 amps by as much as 10%, although the available short circuit current is below the circuit breaker rating of 25,000 amps in all cases. The licensee stated in its March 20, 1987 letter that an evaluation of the bus bars indicated that the bus does have enough design margin to withstand 25,000 amps without damage.

The review of cable sizes and breaker ratings identified three circuits for which corrective action was required to ensure compliance with Appendix R. The action taken prior to restart from the 6R refueling outage is documented in the licensee's March 20, 1987 letter.

The next report reviewed by the staff as part of this unresolved item was a voltage drop calculation performed by the licensee on March 20, 1987, to assure that the new circuitry installed as part of the Heat Sink Protection System (HSPS) during the 6R refueling outage meets the TMI-1 criteria for degraded grid voltage conditions. The subject criteria are contained in Technical Data Report (TDR) No. 114, dated April 29, 1980. The criteria require that safety related valve motors rated at 460 volts have the capability to start at 75% or greater rated voltage. Motor starters (controllers) must be able to pick up at 75% or greater voltage and drop out at 55% rated voltage. The worst case motor (power) circuit used for the study was that for valve FW-V-5A. Assuming a degraded voltage at the motor control center of 410 volts, the calculated voltage at the motor was 82.4% of rated voltage. The worst case control circuit used for the study was that for valve FW-V-92A. The calculation showed that 79.1% of rated voltage would be available at the controller. The evaluation concluded that TMI-1 voltage drop criteria was met for the HSPS. The staff finds that the methodology for this evaluation was appropriate and the results were correct.

The staff reviewed a failure modes and effects analysis (FMEA) prepared for the licensee on the HSPS by Impell Corporation. The FMEA is documented in Impell Report No. 02-0370-1389, dated March 16, 1987. The FMEA concluded that it is not credible that failures of the normal or backup power supplies will have an adverse effect on the HSPS. The staff believes that the FMEA was appropriately conducted and that it achieves its intended purpose. Additionally, staff audit and inspection activities related to loss of power to Class 1E and non-Class 1E buses provide added assurance that vulnerabilities to these events are minimal.

The staff was provided a calculation regarding loop errors for the Once Through Steam Generator (OTSG) water level instrumentation. The calculation was performed by Impell Corporation and documented in report No. 0370-129-001, dated March 19, 1987. Although the calculation appeared to be appropriate for its intended purpose, the staff lacked detailed information regarding environmental affects and manufacturer instrument tolerance. This subject has been addressed in report No. 87-09.

The staff had noted that the minimum separation distance of 6 inches between Class 1E and non-1E wiring was not maintained in Section T5 of HSPS Cabinet A1. In March 1987, the licensee corrected this problem either by wire wrapping with fire retardant material or rerouting internal wiring. In cases where the licensee was unable to perform wire wrapping or rerouting, an engineering evaluation was performed to verify that the condition was acceptable. The corrective action proposed by the licensee meets the cable separation criteria as specified in R.G. 1.75. The NRC staff reviewed licensee corrective actions and has no further concerns.

One final issue was reviewed as part of this unresolved item. The emergency feedwater system (EFW) is designed to deliver water to the steam generators for removing decay heat during a loss of main feedwater or during a loss of four reactor coolant pump (loss of offsite power) condition. The EFW consists of two motor-driven pumps and one turbine-driven pump which uses steam from the main steam line for motive power. The steam supply to the turbine driven EFW pump is provided by two trains from separate main steam lines. The steam supply valves (MS-V13A/B) from both trains are designed to automatically open simultaneously in the event of an EFW actuation to supply steam to the turbine driven pump. There are also two normally closed parallel motor operated steam supply valves (MS-V10A/B) which are remotely opened to increase the steam flow rates as necessary, such as at low steam pressure conditions. Steam pressure to the turbine is controlled by means of a pneumatic pressure controller (PC-5) and regulating valve (MS-V6). Two safety relief valves (MS-V22A/B) were originally set to lift at 200 and 220 psig respectively.

During the 1985 restart startup testing of TMI-1, the licensee found that the safety relief valves lifted when automatically starting the turbine driven EFW pump. Pump operation was maintained with the relief valves not completely closed. The plant operations personnel reseated the relief valve by gradually reducing the setpoint (thumbwheel) on the steam supply pressure controller, and then returning the setpoint to normal after the relief valve closed. Therefore, the relief valve lifting problem did not prevent the turbine driven pump from functioning and it remained operational throughout the test. In its letters dated October 11, and December 20, 1985, the licensee committed to investigate the problem and complete system design and operational reviews or changes in the steam supply line, if required, prior to returning the unit to power. As a short term modification, the licensee changed the existing operating mode of the steam supply valves for Cycle 5 operation by automatically opening valve MS-V13A only in order to reduce steam line pressure and remotely opening valve MS-V13B if MS-V13A fails in the closed position.

By letter dated March 20, 1987, the licensee submitted its final modification and analysis for the implications of the lifting of the EFW turbine driven pump main steam inlet safety relief valves. The final modification and performance testing were made during Cycle 6 refueling outage as part of a 10 CFR 50.59 change. The inspectors reviewed the licensee's safety analysis. Results are given below.

In its submittal, the licensee identified that the root causes of the turbine driven EFW pump steam admission line safety relief valve lifting were attributable to a combination of:

(a) a narrow margin between MS-V22A/B setpoints (200/220 psig) and the pneumatic pressure controller (PC-5) setting (150 psig) for the turbine driven pump inlet steam regulating valve (MS-V6), and

(b) the inability of the MS-V6/PC-5 control loop to respond fast enough and throttle the increased steam supply which results from the simultaneous opening of the two steam supply valves (MS-V13A/B).

The licensee resolved the above problems with the following system modifications:

(1) Installation of two new main steam inlet relief valves (MS-V22A/B) to replace the old valves. The new valves have higher lift setpoints (260/280 psig) than the old valves

(200/220 psig).

(2) Changes in the pneumatic pressure controller (PC-5) for the pump inlet steam pressure control valve (MS-V6). The new proportional plus integral type controller has the capability to control inlet pressure at a desired value under a wider range of operating conditions.

(3) Modification to the control logic for the steam supply valves (MS-V13A/B) to delay the opening of the second valve (MS-V13B) by no greater than 60 seconds but no less than 40 seconds to reduce steam line pressure.

In addition to the above noted modifications, the licensee also performed several tests after completion of the above modifications to verify proper turbine driven pump performance. In the March 20, 1987 submittal, the licensee provided an analysis of turbine pump operation with the new safety relief valve setpoints and a discussion of its operability under various abnormal conditions. The new relief valve setpoints were calculated for 3 percent and 10 percent accumulation type safety valves with a 3 percent tolerance range for a maximum allowable pressure of 300 psig in the pump turbine. The NRC reviewed the setpoint analysis and found that the setpoints (260/280 psig) established for the new relief valves are sufficient to prevent overpressure in the EFW pump turbine. In addition, the 40 to 60 second time delay in opening the second steam supply valve can further reduce challenges to the relief valves by lowering the steam inlet pressure. The analysis also considered potential functional deficiencies that could affect the pump operability such as (1) one or both steam supply automatic valves (MS-V13A/B) open and one relief valve stuck open, (2) either of the parallel steam supply remote manual valves (MS-V10A/B) open and one relief valve stuck open, or (3) minimum OTSG pressure. Based on the analysis, the licensee determined that the pump could be operable with one relief valve stuck open only if one or both valves MS-V10A/B were open and with a minimum OTSG pressure of 492 psig.

The licensee stated that the greater margin between the new relief valve setpoints and steam pressure controller setpoint will make it less likely that steam transients will lift the safety valves. The increased relief valve setpoints (260/280 psig) are still below the turbine design pressure (300 psig) thereby providing the necessary overpressure protection. The adequacy of these changes was also verified by tests as discussed above.

Based on the above discussion, the NRC concluded that the licensee's modification, analysis and testing for the EFW turbine driven pump steam supply are adequate to ensure proper pump operation, and are therefore acceptable. These items are closed.

7.2 (Closed) Unresolved Item (50-289/87-06-08), Heat Sink Protection System Engineering Analysis Review

NRC Region I conducted a readiness review at TMI-1 for Cycle 6 startup (March 1987) that included a limited safety system functional inspection of the newly installed Heat Sink

Protection System (HSPS). A number of engineering analyses were performed by the licensee in support of this system. The analyses varied in length, detail, and thoroughness and were given a cursory review at the time by the inspector to assure that the licensee had completed the required actions prior to startup and that there were no obvious safety issues. The NRC has completed this review as discussed in the following paragraphs.

The NRC reviewed the licensee's single failure analysis of the Two Hour Back-up Instrument Air (2HBUIA) system as documented in Technical Data Report (TDR) No. 848 dated 3/13/87. This system is required as a backup supply of control air for the HSPS (as well as other systems) because the instrument air system (IAS) is not classified as safety-related. The staff also visited the TMI-1 site and performed a walkdown of the 2HBUIA system. The 2HBUIA system is required as a backup supply of compressed air to the main steam and emergency feedwater (EFW) systems air-operated valves to permit uninterrupted valve operation for a minimum of two hours assuming loss of all AC power (station blackout). The 2HBUIA lines are 1/2 to 2 inch stainless steel pipes which are physically separated from high energy lines, so that a high energy line break (HELB) has no effect on the 2HBUIA. The licensee analyzed independent failures in each of the individual isolation valves between the normal instrument air system and the 2HBUIA, and summarized the consequences of a single failure of these valves. The licensee identified that one failure mode may have the potential for depletion of the 2HBUIA supply, but no other single failure could prevent the system from performing its safety function. To correct the identified failure mode, the licensee modified the system by adding an isolation valve to manually separate the 2HBUIA "B" train from supplying the associated components of the EFW turbine driven pump steam pressure control valve (MS-V6). The NRC has reviewed the licensee's single failure analysis of the 2HBUIA and finds that the analysis has adequately considered design basis failure modes, and is therefor, acceptable.

The HSPS includes main steam line rupture detection and emergency feedwater automatic initiation devices which were required by TMI Action Plan (NUREG-0737), Item II.E.1.2. The function of the HSPS is to either stop main feedwater flow into a failed Once Through Steam Generator (OTSG) or initiate and control the EFW system when conditions warrant. Pipe rupture scenarios such as a main steam line break could affect the HSPS performance.

As part of the analysis for protection of the HSPS from HELBs, the licensee conducted a walkdown of the system in the intermediate building. The NRC also conducted a walkdown in the intermediate building, accompanied by licensee personnel, in order to independently evaluate potential pipe rupture effects on the HSPS including pipe break locations, protection devices, and identification of instruments or components to be protected from an HELB. The NRC inspected the HSPS process instruments and their relative position to the postulated pipe rupture point and found that they were properly protected to ensure their availability during accident conditions. The licensee did not include a walkdown of the HSPS inside containment as part of the system technical analysis. By letter dated June 8, 1988, in response to a staff request, the licensee provided reasons for not performing an HELB effect walkdown inside containment. The NRC staff reviewed the licensee's submittal and the containment piping arrangement drawings and agreed that a containment walkdown is not necessary due to the separation provided HSPS sensing lines inside containment. Based on the above discussion and HELB walkdown, the staff concludes that the HSPS was in conformance with its design basis for ensuring the availability of emergency feedwater flow during accident conditions and, therefore, is acceptable.

The NRC staff reviewed documentation, primarily Wyle Laboratories Test Report No. 48681-1 dated March 20, 1987, supporting the seismic Category I qualification of five instrument air devices in the control system for MS-V6. A Model 2625 Volume Booster, a Model 4195BFE Pressure Controller, a Model 3582 Valve Positioner, a Model 95H Instrument Air Regulator, and a Model 67AFR Instrument Air Regulator were subjected a seismic test program on February 26 and 27, 1987. The program consisted of two test series. During test Series 1, the specimens, as described above, were subjected to a resonance search testing and triaxial random multifrequency testing. The specimens were instrumented with accelerometers, pressurized, and monitored for functional operation before, during, and after the random multifrequency testing. During Test Series 2, the Model 3582 Valve Positioner was subjected to Operating Basis Earthquake (OBE) level single-axis sine sweep tests and Safe Shutdown Earthquake (SSE) level single-axis sine beat testing. The Valve Positioner was instrumented with accelerometers, pressurized, and monitored for functional operation before, during, and after the required input motion. The single-axis sine beat test were performed with acceleration of 0.65g horizontally and 0.32g vertically over a frequency range of 2 to 35 Hz. The OBE and SSE for TMI-1 are 0.06g and 0.12g, respectively. The test report concluded that the test specimens demonstrated sufficient integrity to withstand, without compromise of structures or functions, prescribed simulated seismic environment. The NRC staff reviewed this report and other supporting documentation for methodology and completeness. The staff also compared the test input motions with the licensing basis ground acceleration response spectra (TMI-1 Final Safety Analysis Report, Figure 2.7-1) to assure that the design basis was adequately simulated during the test over the entire spectra. The staff concluded that the MS-V6 air control system seismic test procedure was adequate and that the test was properly conducted and documented.

The final review conducted as part of this Unresolved Item was documentation of a seismic Category 2 over seismic Category 1 walkdown performed by the licensee. The walkdown was performed by the architect/engineer, Gilbert Commonwealth Inc., on behalf of the licensee and was documented in a letter dated March 10, 1987. The area of concern was cable trays and conduit supports in the vicinity of the HSPS cabinet installed during the 6R refueling outage. The letter stated that half of the affected supports were formally analyzed in 1986 and that the remainder of the supports can be shown to be anti-falldown by large margins by virtue of similarity to analyzed supports. The NRC staff sees no reason to disagree with this conclusion. The NRC staff conducted independent walkdowns on two occasions after the licensee walkdowns with participation by an NRR structural engineer during on of the walkdowns. The NRC staff has found no reason to believe that unidentified seismic 2/1 problems exist in the vicinity of the HSPS cabinet. The NRC staff notes that the licensee is committed to conduct an extensive seismic verification walkdown by NRC Generic

Letter 87-02. This generic letter implements the resolution to Unresolved Safety Issue A-46 and the walkdown is presently scheduled for the 10R refueling outage in 1993.

Based on the above noted evaluations, licensee action of this item was considered adequate by the staff and this item is closed.

7.3 (Closed) Unresolved Item (50-320/88-30-01) Iodine Sampling Technique of RMA-5

This item consisted of three (3) sub-items (Sub-items 1, 2 and 3) relating to an indication of iodine breakthrough for the condenser offgas sampling system. Items 1 and 2 were closed during the previous inspection conducted on August 15-16, 1989 (see Inspection Report No. 89-17). The licensee responded to Item 3; evaluation of other iodine effluent sampling systems for the possible breakthrough, to the NRC on October 18, 1989. The licensee evaluated and concluded that there was no indication of the iodine breakthrough for other sampling systems.

The inspector reviewed the licensee's evaluation and had no concerns. This item is closed.

7.4 (Closed) Unresolved Item (50-320/89-08-01) Live Electrical Cable Leads from Plasma Cutting Incorporated (PCI) Equipment in the Reactor Building

This item concerned the discovery of live electrical leads in the reactor building of TMI-2 that came in contact with other metallic surfaces and caused visible arcing. Subsequent investigations determined that an isolation device that was red tagged had inadvertently become mispositioned which allowed the disconnected leads to become energized. The leads had been connected to PCI equipment which has been removed from the reactor building.

The licensee investigated the problem and determined that the work package had not been adequately reviewed for isolation, that the red tag was inappropriately placed on a control switch verses an electrical breaker and that workers removed part of the PCI equipment with another red tag attached.

The licensee corrected the problem by removing the subject cables and reviewing the matter with appropriate personnel. The inspector reviewed the corrective action prescribed in incident report No. 50-320-89-043 completed on February 2, 1990. The corrective action was adequate to address the problem and prevent further occurrences of this type. This item is closed.

7.5 (Open) Inspector Followup Item (50-289/89-82-009) Weakness in Procedure to Inspect and Test Slings and Hoisting Equipment

This item noted some weaknesses with maintenance procedures associated with the inspection and testing of slings and hoisting equipment. The licensee's response was that the procedures would be upgraded as part of the biannual review process. This action has not been completed yet and, therefore, will be inspected at a later date.

7.6 (Closed) Unresolved Item (50-289/89-80-01) Correction of Human Factors Discrepancies in Emergency Operating Procedures (EOP)

This item concerned the licensee review and correction of minor human factors type discrepancies in various emergency procedures which were evaluated during the EOP team inspection. Approximately 38 emergency (1202 series) and abnormal (1203 series) procedures were reviewed by the team. The licensee has completed the review of the inspection comments and has been incorporating changes, as deemed appropriate, as the procedures come due for biannual review. The inspector reviewed several procedures that had the appropriate changes incorporated and concluded that the licensee program to effect human factors type changes was adequately implemented. Although not all the procedures have been reviewed and changed, the licensee progress in this area was adequate to resolve the inspector's concerns. This item is closed.

7.7 (Closed) Violation NC4 (50-289/89-82-01) Failure of Electrical Maintenance Personnel to Sign-On the Clearance Control Document per Administrative Procedure AP 1002

This violation concerned the fact that electrical maintenance personnel who were performing modification to the "A" emergency diesel generator (EDG) failed to sign-on the clearance control document (CCD) prior to starting work. This is required by licensee AP 1002, Rules for the Protection of Employees Working on Electrical and Mechanical Apparatus. The problem was that the licensee personnel completing the modification work assumed that the individual who was responsible for all work on the EDG had already signed on the CCD for the work they were doing.

The licensee subsequently revised AP 1002 to allow the computer generated work schedule document used for system outages to be attached to the CCD and signed-on by the foreman or maintenance supervisor in charge of the entire work package. This individual is then responsible to ensure that the tagout is adequate for all the work items being accomplished.

The inspector reviewed the procedure change and also several recently implemented tagouts and CCDs used for system outages. The licensee had properly implemented their new procedure. It appeared to the inspector that the administrative system for work and tagout control is now adequate and properly implemented by the licensee. The inspector had no safety issues with licensee action in this area and this item is closed.

7.8 (Open) Violations NC4 (50-289/89-82-02) and (50-289/89-82-03) Improper In-plant Storage of Material and Improper Control of Test Equipment

These items remain open pending completion of licensee corrective action. These violations were issued in April of 1990 and the licensee committed to complete corrective action by November 15, 1990. This action has been completed and the licensee is in the process of documenting the completion. The inspector will review the completed corrective action in future inspections.

7.9 (Closed) Inspector Followup Item (50-289/89-82-004) Engineering Evaluation Requests (EER) not completed in Accordance with Plant Procedures and EER Backlog

This item noted that tracking of Engineering Evaluation Reports (EERs) was not well controlled in that several EERs were misplaced and were later found. This item also noted a sizeable backlog of EERs.

To help better control EERs, the licensee has changed Plant Engineering Procedure requiring an engineer to perform an initial screening of EER requests and then assigning a number to the EER. This has helped to ensure that the engineering department is aware of new EERs and that they are resolved in a reasonable time frame.

To reduce the backlog of EERs, the licensee has made a goal of reducing this backlog to an acceptable size by the end of the year such that no EER will be greater than 60 days old. It appears that the engineering department commitment, in this area, has significantly reduced the EER backlog. The NRC will continue to monitor this area. The inspector had no concerns regarding the licensee's commitment and ability to meet this goal.

This item is closed.

7.10 (Closed) Inspector Followup Item (50-289/89-82-005) No Indication as to which Portions of Generic Procedures are Applicable

This item noted that Administrative Procedure 1001A, Procedure Review and Approval, did not require maintenance procedure review and approval for specific jobs in which instructions did not already exist. To correct this weakness, AP 1001A has been changed to reflect that maintenance procedures written for a specific job must receive the same review and approval that is required by other standing or pre-approved procedures.

Another item noted that technicians performing work were making the decision as to which portions of the generic procedures were applicable to the job being performed. To correct this weakness, the licensee has written a memorandum requiring the Planning Department to specify the procedure sections to be performed.

The inspector had no concerns with licensee corrective action. This item is closed.

7.11 (Closed) Inspector Followup Item (50-289/89-82-006) A Number of Vendor Manuals were not in Vendor Document Control Program

This item noted that 30 vendor manuals had been lost or misplaced over a three year period. The licensee indicated that there are about 45 unique distribution points for the approximately

10,000 manuals issued and that although the number of missing manuals was relatively small, this number could be reduced further. The licensee issued a memorandum to all major distribution point department heads stressing the importance of proper sign-out of manuals.

The inspector had no further concerns regarding this item. This item is closed.

7.12 (Closed) Inspector Followup Item (50-289/89-82-007) Improvement Warranted in the Storage of Some Material in Warehouse

This item identified the need to improve the storage of some material in the warehouse. It was noted that some valves in storage were not capped as recommended by licensee's procedures and snubbers were stored in a manner which could cause damage. The licensee had directed it's warehouse supervisors to increase their awareness and has completed training of warehouse personnel on the storage conditions of material. The licensee also conducted a row-by-row inspection of stored material.

The inspector reviewed the licensee corrective actions and conducted an inspection of the warehouse and found no further discrepancies. This item is closed.

7.13 (Closed) Inspector Followup Item (50-289/89-82-008) Inadequate Corrective Action for QA Findings Associated with Equipment Storage

This item noted that usage cards used to check out test equipment were not always being used. During a QA audit a similar finding dealing with usage cards associated with micrometers was noted. The inspector found that failure to take effective corrective action for this was a weakness. The licensee has indicated that during the QA audit, they did not find a programmatic weakness in the use of usage cards but found an isolated incidence of improper use of usage cards associated with micrometers. Therefore, the corrective action expected was only associated with the usage cards for micrometers.

The inspector reviewed the licensee audit finding associated with this item and found the licensee correction action, in this case, was appropriate. This item is closed.

8.0 Exit Meeting

A summary of inspection findings was further discussed with the licensee at the conclusion of the report period on December 3, 1990. Persons designated with an asterisk in Section 1.3 were present at the exit meeting.