U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report No. 50-289/87-19 Licensee: DRP-50

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

Facility: Three Mile Island Nuclear Station, Unit 1

Location: Middletown, Pennsylvania

Dates: October 2 - 31, 1987

Inspectors: R. Conte, Senior Resident Inspector (TMI-1)
D. Johnson, Resident Inspector (TMI-1)
S. Peleschak, Reactor Engineer, Region I

Reporting
Inspector: R. Conte, Senior Resident Inspector

Approved by: C. Cowgill III
C. Cowgill, Chief, Reactor Section No. 1A, DRP 12/22/87
Date

Inspection Summary:

The NRC resident staff conducted safety inspections (160 hours) of the plant operations, maintenance, and surveillance areas which specifically included: simultaneous inoperability of both emergency diesel generators; the reactor protection system (RPS) trip breaker replacement; and, pressure switch calibration for the nuclear service river water system. Other areas reviewed were: independent verification program (IVP); control room environment; storage of transient equipment in safety-related areas; Licensee Event Reports; and, licensee followup/response to previous inspection findings.

The inspectors also performed an inspection at the corporate office of the following: allegation review and followup; Nuclear Safety and Compliance Committee activities; outage/long-range planning for Cycle 7R; technical support reassessment; and, safety evaluations.

8801120274 871228
PDR ADOCK 05000289
Q DCD

1a

Inspection Results:

Licensee management attention and involvement, especially in daily activities, continued to be noted. As evidence of this, the licensee instituted a six-month preventive maintenance replacement of reactor protection system breaker. In general, procedures were properly implemented.

However, certain personnel performance problems were noted; one of these resulted in a violation on failure to properly follow lifted lead administrative controls (see paragr.ph 3.2.2). Other underlying causes appear to be a combination of the following: poor attention to detail; poor technical and safety review and/or poor training in system classification, along with the scope of applicability for independent verification.

The verification of correct operating activity procedures met revised licensee commitments in this area. Weaknesses were noted in the applicability of the program to certain areas. Problems were noted with the licensee's response on the independent verification program.

The corporate staff was adequately supporting TMI-1 safe operations. Three unresolved items were identified during this review (paragraphs 5.2 and 5.5).

DETAILS

1.0 Introduction and Overview

1.1 NRC Staff Activities

The purpose of this inspection was to assess licensee activities during the power operations mode as they related to reactor safety and radiation protection. Within each area, the inspectors documented the specific purpose of the area under review, acceptance criteria and scope of inspections, along with appropriate findings/ conclusions. The inspector made this assessment by reviewing information on a sampling basis through actual observation of licensee activities, interviews with licensee personnel, measurement of radiation levels, or independent calculation and selective review of listed applicable documents.

The resident inspectors also assisted in the monitoring of the annual emergency preparedness exercise of October 22, 1987, as documented in NRC Inspection Report No. 50-289/87-16.

1.2 Licensee Activities

During this period, the licensee operated the plant at essentially full power.

2.0 Plant Operations

2.1 Criteria/Scope of Review

The resident inspectors periodically inspected the facility to determine the licensee's compliance with the general operating requirements of Section 6 of the Technical Specifications (TS) in the following areas:

-- review of selected plant parameters for abnormal trends;

-- plant status from a maintenance/modification viewpoint, including plant housekeeping and fire protection measures;

-- control of ongoing and special evolutions, including control room personnel awareness of these evolutions;

-- control of documents, including logkeeping practices;

-- implementation of radiological controls; and,

-- implementation of the security plan including access control, boundary integrity, and badging practices.

The inspectors focused on the areas listed in Attachment 1.

2.2 Findings/Conclusions

2.2.1 General

The inspection focus by the NRC resident office during this inspection period was the followup on a number of outstanding items, some of which involved major plant operational programs. The results of these reviews are documented elsewhere in this report, such as for the independent verification program (Section 4) and control room environment (Section 6).

In general, procedures were properly implemented, except as noted below and in Section 3. Personnel errors occurred, although they did not result in any reportable events. Housekeeping and fire protection measures continued to be properly implemented.

Overall, licensee management continued their detailed attention and involvement in daily activities.

2.2.2 Emergency Diesel Generators not in Engineered Safeguards (ES) Standby

During preparations for Engineered Safeguards and Actuation System (ESAS) testing per Surveillance Procedure (SP) 1303-5.2, the licensee inadvertently removed both emergency diesel generators (EDG's) from the ES standby condition for about two minutes. The situation was immediately recognized by operations personnel and the condition corrected.

The problem occurred when an auxiliary operator (AO) manually tripped the fuel racks for the "A" EDG when the "B" EDG was already blocked from an ESAS auto start capability. The operator who mispositioned the "A" fuel rack lever was not fully aware that tripping the "A" EDG would place both EDG's in an ESAS inoperable status.

A communication problem between operations personnel in the control room and the AO was the primary cause of the problem. The "B" EDG had correctly been placed in the "ES" standby condition, an initial condition for manual start. The AO had incorrectly noted on his copy of the procedure that the "A" EDG was to be run. The AO also failed to communicate to the CRO in the control room which EDG he was tripping. Both personnel assumed that the correct actions were to be taken.

The "A" EDG fuel racks were reset in approximately two minutes and immediately after the control room annunciators indicated the problem. With the EDG's blocked, the CRO repositioned the "B" EDG start and exciter switches to "auto" to place the "B" EDG in ES standby.

The inspector reviewed the event and discussed the problem with the operations staff. An internal Plant Incident Report (PIR) completely and correctly documented the problem. The PIR concluded that, although the safety significance was minor, proper communications need to be observed when complicated, multi-station tests are being performed. The licensee noted that more aggressive use of proper formal communications needs to be implemented to prevent future reoccurrences of this type of problem.

The licensee also evaluated the problem as non-reportable since the Limiting Condition for Operation (LCO) time clock for the condition was not exceeded. The LCO for this condition allows both EDG's to be inoperable for up to eight hours before plant shutdown actions are needed.

The inspectors also concluded that this item was of minor safety significance as operators were quickly aware of the condition and corrected it immediately. Off-site power was available. The inspectors were notified of the event shortly after occurrence at 5:30 a.m. on October 8, 1987. The licensee review of the circumstances concerning this problem was complete and adequate. The inspectors had no other safety concerns on this event.

2.3 Plant Operations Summary

Housekeeping continued to be quite good. Procedures, in general, were properly implemented.

For the above-noted wrong train/component event, the inspector noted a lack of attention to detail on the part of personnel performing the test. Also, the inspector noted that the time of day the surveillance test was performed may have contributed to the problem.

Licensee management continued their detailed attention and involvement in daily activities.

3. Maintenance/Surveillance - Operability Review

3.1 General Criteria/Scope of Review

The inspector reviewed activities to verify proper implementation of the applicable portions of the maintenance and surveillance programs. The inspector used the general criteria listed under the plant operations section of this report. Specific areas of review are listed in Attachment 1. A more detailed review of equipment operability was also addressed below.

3.2 Findings/Conclusions

3.2.1 Reactor Trip Breaker Replacement

The licensee completed the changeout of all six reactor trip breakers (RTB) during this inspection period. The two a.c. and four d.c. breakers (GE-AK-II-25) were changed out, one for one, with breakers that had recently had preventive maintenance accomplished. This replacement was accomplished during weekly reactor protection system (RPS) surveillance testing, such that all six breakers were changed out in a four-week period. This complete changeout is accomplished on a six-month basis.

The inspector reviewed documentation associated with the preventive maintenance for the RTB's and witnessed portions of the breaker changeout and surveillance test activities. The following documents were reviewed:

-- SP 1303-4.1, Revision 53, dated May 22, 1987, "Reactor Protection System;" and,

-- Preventive Maintenance Procedure E-36, Revision 15, dated October 8, 1987, "CRD Trip Breaker Check."

The inspector also discussed the preventive maintenance activities with licensee personnel.

A review of the "as found" data for the RTB's that had been in service, revealed no major breaker degradation. Time response and major breaker operating parameters, were all found to be within specifications such as, spring pressures, trip bar lift pressures, and shunt and undervoltage (UV) coil voltages.

The inspector observed that personnel who were installing the breakers appeared knowledgeable of their task and changeout of two d.c. breakers was accomplished without problems. He also observed portions of SP 1303-4.1 for RPS Channel "C," which verified breaker operability (shunt trip and UV trip) after breaker replacement. No problems were noted.

The inspector concluded that the changeout of the RTB's had been accomplished in a safe and orderly manner. The inspector had no safety concerns on this evolution.

3.2.2 Differential Pressure Switch Calibration

During a review of maintenance activities associated with the "1B" nuclear river water pump (NR-P-1B), the inspector observed an Instrument and Control (I&C) technician performing a calibration check of the instrumentation associated with NR-P-1B. While reviewing the applicable preventive maintenance (PM) procedure IC-15, the inspector noted that the technician had marked "N/A" for the step requiring verification of the use of the "lifted lead" log per Administrative Procedure 1013, Enclosure 5. This step would have required the technician to fill out a lifted lead log entry for some pressure switch connections for NR-DPS-138, the NR-P-1B strainer differential pressure (D/P) switch. The leads were to be lifted to prevent operation of the backwash valve when simulated pressure was increased above the setpoint. The technician had marked the step "N/A" as he believed that the system being worked was not important to safety (ITS). This was an incorrect assumption. The procedure was unclear in defining exactly which systems were ITS.

The inspector notified licensee management of the problem. The licensee immediately reviewed the problem and concluded that the technician had misunderstood IC-15 and the NR systems status as an ITS system. At the same time efforts were initiated to ensure NR-DPS-138 was wired correctly. The technicians from the I&C shop were instructed in the proper use of AP 1013.

Followup licensee long-term corrective action included accomplishing the following.

-- A review of other corrective and preventive maintenance procedures to eliminate any confusion that may exist; i.e., clarification of the decisions on steps that will not be performed in procedures which are to be marked as N/A. The licensee representative agreed that the identification of procedures that need to be changed is to be completed by February 2, 1988.

-- Those systems that are classified as ITS will be reviewed with all I&C technicians to ensure their awareness of where independent verification of AP 1013, Enclosure 5, is required.

-- A Procedure Change Request (PCR) will be initiated to clarify the wording in procedure IC-15, which caused confusion for the technician.

As defined above, the licensee's actions will be completed by February 2, 1988.

The inspector concluded the immediate and long-term corrective actions for this problem were adequate to resolve the inspector's concerns.

The licensee concluded that this problem was an isolated occurrence and that, generally, I&C technicians were aware of which systems were ITS. Additionally, it was noted that Enclosure 5 of AP 1013 must be used for all systems -- both ITS and NITS (not important to safety). The "ITS" classification triggers an additional independent verification of lifted lead status on Enclosure 5, if the system being worked is ITS. From a training viewpoint, the inspectors concluded that this was not an isolated case.

The failure of the technician to properly implement the provisions of AP 1013 during the conduct of calibration of NR-DPS-138 in accordance with IC-15 is a violation of TS 6.8.1 (289/87-19-01).

3.3 Operability Summary

From the inspector's review of the reactor trip breaker preventive maintenance procedures, it is noteworthy that the licensee has adopted a preventive maintenance practice to changeout reactor protection system (RPS) breakers at six-month intervals. Test procedures were properly implemented and test results were in accordance with the licensee's acceptance criteria.

The performance problem associated with the pressure switch calibration was due to failure to follow administrative control procedures and it was not indicative of a flaw in the independent verification (IVP) program (see Section 4). However, there were signs of other underlying causes for this event. They are: poor technical and safety review that did not identify the need for updating of sub-tier implementing procedures with respect to IVP and, perhaps, poor training in system classification along with the scope of applicability of the IVP.

The inspector was satisfied with licensee's corrective actions taken or planned for the above-noted violation.

4. Independent Verification Program (IVP)

4.1 Introduction and Background

The NRC staff opened a previously unresolved item (289/85-27-08 - see also paragraph 9.2) because the licensee's program to verify correct operating activities was: (1) not clearly defined in that various sections of TMI-1 hearing records addressed multiple and conflicting attributes of this type of program; and, (2) various administrative control procedures applied this program to a different set of equipment which was not clearly correlatable to the hearing commitments. In addition, the program was not consolidated in addressing TMI Task Action Plan (TAP) I.C.6 key elements (see paragraph 9.2).

The purpose of this review was to assure sufficient licensee resolution of the above items and to assess the technical adequacy of the program.

Overall, favorable results are addressed below, but there is a weakness on the scope of equipment within the IVP.

4.2 Scope of Review

In addition to discussions with cognizant licensee personnel, selected sections of the following documents relating to the independent verification program (IVP) were reviewed.

-- Administrative Procedure (AP) 1001A, Revision 13, effective June 26, 1987, "Procedure Review and Approval"

-- AP 1001D, Revision 11, effective December 10, 1986, "Procedure Preparation"

-- AP 1001K, Revision 9, effective December 10, 1986, "Biennial Procedure Review"

-- AP 1001J, Revision 6, effective July 22, 1986, "Technical Specification Surveillance Testing Program"

-- AP 1002, Revision 49, effective July 17, 1987, "Rules for the Protection of Employees Working on Electrical and Mechanical Apparatus"

-- AP 1013, Revision 23, effective August 5, 1987, "Bypass of Safety Functions and Jumper Control"

-- AP 1029, Revision 25, effective May 20, 1987, "Conduct of Operations"

-- AP 1067, Revision 1, effective March 19, 1987, "Independent Verification Program"

-- Operations Procedure (OP) 1101-3, Revision 45, effective September 25, 1987, "Containment Integrity and Access Limits"

-- OP 1104-28 (Series) - "Solid Radwaste Handling"

-- SP 1302-5.7, Revision 10, effective March 31, 1987, High Reactor Building Pressure Channel"

-- SP 1302-5.10, Revision 16, effective June 2, 1987, "Reactor Building 4 psig Channel"

-- SP 1302-5.11, Revision 10, effective May 5, 1987, "Reactor Building 30 psig Channel"

-- SP 1302-18, Revision 4, effective June 16, 1986, "Calibration of Reactor Building Post-LOCA/Hydrogen Monitor"

-- SP 1302-19, Revision 4, effective May 19, 1987, "Hydrogen Recombiner Instrument Channel Calibration"

-- SP 1302-20, Revision 2, effective September 25, 1986, "Containment Pressure Instrument Calibration"

4.3 Findings/Conclusions

4.3.1 IVP Essential Elements

Operationally important and critical components within safety- related systems are included in the licensee's IVP (AP 1067) using the criteria specified in the licensee's letter, dated April 29, 1986. Essentially all Engineered Safeguards and Actuation System (ESAS), containment, emergency feedwater (EFW) systems are listed, including major flow path valves; key breakers; and, other key components, such as manual flow path valves that, if mispositioned, could disable the train. Manual valves in high radiation areas are generally on the locked valve list. The AP 1067 list does not include drain/vent valves or other components where status would be monitored or verified by other means. These other means would be ESAS checklist (once/shift) or the shift and daily surveillance procedures. Also, there would be an obvious system depressurization if a drain/vent were inadvertently left open. The AP 1067 list also includes control and power supply breakers and control switches for each system within the scope of the program.

The program, as embodied in AP's 1001D, 1001K, 1002, 1013, 1029, and 1067, has administrative controls that are now, in general, consistent with one another. A minor exception was noted (see paragraph 9.2).

Instrumentation is handled separately. The reactor protection system (RPS) is not specifically listed in AP 1067; but, by virtue of the shift and daily check surveillances done on the system, the RPS is routinely verified to be operational. This is also true for the actuation logic of ESAS, but certain components were also listed in AP 1067. Other safety-related instruments (such as wide-range/ narrow-range (WR/NR) reactor building (RB) pressure, hydrogen recombiner instruments, and containment hydrogen monitor) are not necessarily independently verified to be correctly lined up.

Support or attendant equipment is designated with referral to other sections in this AP 1067. The AP 1067 valve listing was developed by review of applicable system drawings.

The AP 1067 states that surveillance procedures (SP's) stand alone on IVP on restoration to normal; and in general, that is true except for safety-related instrumentation as noted above. The biennial review procedure (AP 1001K) verifies that SP's are consistent with AP 1067 guidance. Further, AP 1001D requires that, as a minimum, critical components have independent verification applied when SP's are generated.

The same is true for restoration to normal with respect to switching and tagging related to maintenance work. If no tags are used in minor maintenance effort, a procedural-required form is used which invokes the IVP requirements for critical components.

For plant startup from outages, the AP 1067 critical valve listing is implemented at the discretion of the Plant Operations Director. In general, systems affected by the outage would have the AP 1067 listing verified. Containment integrity is independently verified whenever it is set. The locked valve list is also checked.

4.3.2 IVP Strengths

A number of strengths were noted as a result of the licensee's actions on the IVP in response to NRC concerns..

-- The graded approach highlights safety significant equipment among those components listed as safety related.

-- AP 1013 on temporary modifications (TM's) (bypasses) still applies to "important-to-safety" equipment which includes safety-related equipment.

-- The program was updated to reflect the latest modification work (e.g., Heat Sink Protection System (HSPS)).

-- Specific guidance on how to do IVP is specified in AP 1067 - the doer and verifier must be different.

-- For minor maintenance or maintenance with no tags applied , the control room operator (CRO) must document the independent verification of restoration to normal from maintenance in the CRO log

Analysis is provided below (paragraph 4.3.5).

4.3.3 IVP Weaknesses

The following shortcomings were noted with respect to the currently defined IVP:

-- Some safety-related equipment will be manipulated during operation, maintenance or surveillance and not be independently verified to be restored to normal.

-- The IVP for radwaste and fire protection (FP) essentially does not exist for routine processing/transfers. These system valves are included if they are containment isolation valves. (It should be noted that in the FP area TS requires a monthly alignment check (SP 3301-M1), but this would not necessarily assure correct alignment for times in between the check when equipment is removed from service.)

Analysis is provided below (paragraph 4.3.5).

4.3.4 IVP Implementation

During this inspection period, the inspector independently verified the correct lineup of selected safety-related equipment. This was accomplished using the following methods:

-- routine control room and safety-related areas review and walkdown of selected safety-related equipment;

-- check of the positions for valves and breakers listed in AP 1067 for EFW and its interface systems -- condensate and main steam;

-- selective verification of lineups as listed in the licensee's ESAS checklist and secondary auxiliary operator shift logs focusing on reactor building spray system pressure instruments and EFW and its interface systems - condensate and main steam; and,

-- the calibration activity described in paragraph 3.2.2 of this report.

Within the scope of this review, safety-related equipment was properly aligned to perform its intended function. As described below, minor implementation problems were identified, but none included non-adherences to AP 1067.

Paragraph 2.2.2 describes a wrong train/component situation which resulted in both emergency diesel generators becoming inoperable with respect to ESAS signal for a short period of time. The root cause was a communications problem, but the inspector also reviewed the event with respect to IVP. For the situation described, IVP was not applicable since the licensee was in the middle of a surveillance test. The IVP's purpose, in part, is to verify equipment to be restored to normal. This does not reflect a weakness in the IVP, although an incorrect activity was performed. Closer attention to detail could have prevented it. Control room operators were attentive to quickly correct the problem.

Paragraph 3.2.2 of this report describes a licensee individual's failure to follow the applicable administrative controls for lifting leads in safety-related equipment. Contributing to this event was a procedure adequacy problem in that it still used the pre-AP 1067 terminology of selective applicability of IVP to certain safety-related equipment. However, another section of the procedure properly invoked AP 1013 requirements, but the individual apparently did not fully understand the system's classification that he was working on. In any case, these problems do not reflect adversely on the adequacy of the IVP per AP 1067 and AP 1013. It is clear that the clarification in scope of equipment to be independently verified per AP 1067 was not adequately reflected in sub-tier implementing procedures and this reflects a weakness in the licensee's technical and safety review process.

Section 8 of this report describes Licensee Event Report (LER) No. 87-009 (see also NRC Inspection Report No. 50-289/87-17, paragraph 2.2.1) on an effluent radiation monitor interlock (with discharge valve) being inoperable during a release. The LER describes several personnel errors on the part of maintenance and operations staffs. However, procedure enhancements were also planned to verify and control the proper positioning of the interlock defeat/enable switches in the release sequence. The inspector reviewed this event for any adverse implications to the IVP. The particular enable/defeat switches were included in AP 1013, which provides control measures for the bypass of safety functions. These measures were not properly implemented by the personnel and/or by the sub-tier calibration/ operational procedures. The inspector concluded that this was not a weakness in the IVP, but it does reflect a weakness in the licensee's technical and safety review process.

The events described above do indicate a need for closer attention to detail, better technical and safety reviews, and additional training in the area of safety classification and scope of IVP applicability.

The inspector concluded that the IVP is being properly implemented.

4.3.5 Evaluation of the IVP

Evidence indicates that the past and current IVP programs, in general, have been effective at least since 1983. In September 1983, there were a number of containment integrity violations when the plant was in hot functional testing. The IVP was then enhanced on a limited basis. The inspector has reviewed LER's since then and he concluded that none of the LER's were due to flaws in the IVP. There also have not been significant safety events as a result of IVP weaknesses in the past two years of power operations. (Paragraph 4.3.4 alludes to weaknesses in other areas.) Further, the implementation review noted above confirmed the proper alignment of the EFW and reactor building spray systems, as examples.

The IVP (per AP 1067) does not stand alone, however. A number of other controls constitute a verification of correct operating activities in addition to AP 1067 measures.

-- ESAS checklist done on a shift basis supplemented by various checks done by the primary, secondary, and outbuilding auxiliary operators.

-- Locked valve list as required by AP 1011, "Controlled Key Locker Control."

-- Shift and daily checks (SP 1301-1) and weekly checks (SP 1302-4.X series of procedures).

Proper implementation of these measures were also independently verified by the inspector, based on this review.

Licensee management has agreed that there has been an enhancement to safety as a result of their efforts to respond to NRC staff concerns in this area. The AP 1067 now clearly defines what components are important and, accordingly, what components deserve the special attention of the IVP. Licensee management indicated their receptiveness to resolve any future NRC staff concerns if incorrect activities should occur. They emphasized that future (independent verification) corrective actions would probably be procedure specific to the component(s) involved so as not to dilute the importance of critical valves listed in AP 1067 with a program expansion.

The licensee should strongly consider incorporating independent verification measures into facility procedures dealing with the below-listed systems before any major events occur as a result of a lack of independent verification.

-- Fire protection

-- Solid, liquid, and gaseous radwaste

-- Safety-related instruments not within the scope of RPS/ESAS periodic tests

In conclusion, the licensee's programs for verifying correct operating activities meet revised commitments in this area. A number of strenghts with the programs were noted. The weakness is centered around the scope of applicability of IVP. To date, this weakness has not adversely affected safe plant operations. Accordingly the backfit process is inappropriate at this time (see paragraph 9.2).

4.3.6 Procedure Clarifications

During the review of AP 1067, the inspector noted some minor discrepancies for which the licensee is agreeable to resolve by the next revision to AP 1067.

-- Paragraph 4.3.b.1 of AP 1067 on the use of remote indication by two different people does not have a "caution" or "note" to assure that direct indication be available in distinction to power demand signal lights. The licensee agreed to provide such a highlight.

-- Paragraph 6.0 of AP 1067, on References, lists the first licensee response letter of April 29, 1986. The other licensee response letter of June 3, 1987, was not included and it provides additional program description. The licensee agreed to incorporate the latest licensee letter by reference into AP 1067.

4.4 IVP Program Summary

The licensee's procedures for verifying correct operating activities meets revised commitments in this area. A weakness was identified in that IVP applies to a subset of safety-related equipment. However, program implementation has, in general, been quite good without events involving major safety significance. Performance problems with respect to verifying correct activities are not correlatable to IVP weaknesses. They point out a need for closer attention to detail, better technical and safety reviews, and additional training in the area of safety classification and IVP scope applicability.

5. Corporate Inspection

5.1 Introduction

The Senior Resident Inspector (SRI) (TMI-1) conducted an inspection at the licensee's corporate headquarters in Parsippany, New Jersey, on October 13-15, 1987. The main focus of the inspection was to follow up on various previously identified open issues (as described below) to assess licensee actions toward resolution of these items or to assess proper implementation of selected corporate-level programs in support of TMI-1 safe operations. Many of these issues are either identified in past inspection reports or in the latest SALP (Systematic Assessment of Licensee Performance) process.

5.2 Allegation on Polar Crane Operation - Procedural Controls

On September 3, 1987, the SRI (TMI-1) received an allegation on procedural controls for the operation of the reactor building (RB) polar crane (No. RI-87-A-0108). The polar crane is used to lift heavy loads within the RB to support refueling outage-type work. The licensee employee's concern apparently developed during the last refueling outage (November 1986 to Ma..n 1987) and they centered on the following:

-- the director or sig alman for RB polar crane operator was not equally qualified (medically and/or trained) as the operator of the crane; and,

-- licensee management arbitrarily deleted these apparent procedural requirements.

The individual came to NRC apparently because he felt he had a safety concern and because he felt that licensee management was not effectively resolving the issue. The inspector encouraged the individual to use the licensee's internal systems, such as the "Ombudsman Program," to resolve his issue; but the inspector acknowledged that NRC staff would review the matter.

After his conversation with the inspector, the individual apparently informed the licensee's ombudsman of the issue on the same day. As a part of Region I's review of the matter, it was decided to let the licensee's ombudsman review the matter and then the NRC staff would re. ew the licensee's results. While at the corporate office, the inspector discussed the concerns with the licensee's ombudsman and the engineer assigned to resolve the problem.

In addition to the above-noted conversation, the inspector reviewed the following licensee documents/records:

-- Maintenance Procedure (MP) 1406, Revision 9, dated December 8, 1986, "Crane Operator Qualifications;"

-- Refueling Procedure (RP) 1507-1, Revision 6, dated December 8, 1986, "Polar Crane Operation;"

-- ANSI B30.2.0 - 1976, "Overhead and Gantry Cranes;"

-- Temporary Change Notice (TCN) No. 1-86-087, dated November 21, 1986, to RP 1507-1, Revision 5; and,

-- Licensee Internal Memorandum, dated Septembe 23, 1987, from 1. Mengel to R. German on "Review of Change to .I-1 Polar Crane Operating Procedure."

The inspector had the below-listed findings on the licensee's review of the matter.

Prior to the last refueling outage, MP 1406 implied that the director (or signalman) be qualified to the same standards as the operator. The TCN 1-86-087 was initiated, reviewed, approved, and issued to more clearly state requirements. The requirements for qualification apply only to the operator, not the signalman. It is the operator's responsibility that the signalman, if used, can adequately communicate signals to assure safe crane operation. This is consistent with ANSI B30.2.0 - 1976, which is referenced by NUREG 0612, "Control of Heavy Loads," to which the licensee is committed.

During the licensee's review of this matter, it was identified that RP 1507-1 and 1507-2 (for Fuel Handling Building Crane) had hand signals that were inconsistent with the 1976 version of the ANSI Standard. The licensee planned to revise RP 1507-1 and 1507-2 to make the designated signals consistent with that committed to in the standards.

The inspector independently confirmed the licensee's findings. The ombudsman also reported that licensee Quality Control (QC), and Safety and Health personnel agree with the ombudsman's findings.

The ombudsman reported that he discussed his findings with the concerned employee on September 25, 1987, but the employee did not appear to be satisfied. The employee raised another specific allegation (discussed later) and he indicated that this issue (additional allegation) and the one on the polar crane were indicative of a broader issue -- the nuclear safety implications of working people out of a job classification by procedural word changes. The licensee representative reported that the employee indicated that a labor relations grievance would be filed; but, as of the end of this inspection period, the employee had not filed such a grievance.

The gist of the other allegation was the potential nuclear safety implications of operations personnel doing a job that is also done by maintenance technicians. The ombudsmen indicated that they would review this additional allegation with respect to nuclear safety.

This is unresolved pending completion of the licensee's review of this matter and subsequent NRC Region I review (289/87-19-02).

Based on this review, the original allegation (No. RI-87-A-0108) is considered closed.

5.3 Nuclear Safety and Compliance Committee Activities

At the corporate and site, the inspector reviewed Nuclear Safety and Compliance (NSCC) activities to assure that the applicable restart condition (No. 1.t) was continued to be met. The inspector conducted a more detailed review in NRC Inspection Report No. 50-289/86-19. In addition to discussions with the NSCC staff members, the following records or documents were reviewed:

-- GPUN Board of Director Meeting Minutes on the NSCC report of activities for the period November 1986 to August 1987; and,

-- NSCC Semi-Annual Report (No. 6), dated April 8, 1987, for the period October 1, 1986, to March 31, 1987.

The inspector continued to note that events or NSCC staff findings unique to the sites (which are not necessarily receiving much publicity) are being followed by the NSCC staff and reported to the GPUN Board of Directors. This continues to be advantageous in that it enhances the board's knowledge of a number of issues at both Oyster Creek and TMI-1.

The inspector also noted substantial attention by the NSCC and its staff to past significant events at Oyster Creek. There also appears to be an appropriate level of attention to TMI-1 activities. The inspector also noted the identification and tracking of issues raised by NSCC.

The NSCC staff leader reported on a number of licensee actions that could be considered measures of the effectiveness of the NSCC and its staff.

Except in one area, details will not be given since the inspector had not made any recent observations in the areas. Accordingly, the inspector would not be able to judge whether licensee performance improvements have really occurred, nor would the inspector be able to judge if they were as a direct result of NSCC activities or other groups, outside company activities. What was important was that the NSCC staff was evidently reviewing its own activities and attempting to assess its impact on enhancing licensee performance.

The above-noted exception was in the area of logkeeping. Like the NSCC staff, the inspectors have noted improvement in the details given in control room narrative logs on off-normal events at the plant, which are not reportable to the NRC. However, as noted in NRC Inspection Report No. 50-289/87-17, it does appear that the threshold is still high for formal review of such events using such mechanisms as the plant incident reporting system.

The inspector had no additional comments on the NSCC and its staff's activities.

5.4 Outage/Long Range Planning

At the corporate office, the inspector reviewed outage/long range planning with the cognizant manager and selectively reviewed Topical Report 042, Revision 1, dated October 8, 1987, "TMI-1 Nuclear Generating Station Long Range Plan, Cycle 6 through 9R." The purpose of this review was:

-- familiarization and assessment of long range plan; in particular, the Cycle 7 refueling outage;, and,

-- assure regulatory issues or required modifications were incorporated into the plan.

The inspector determined that the licensee has adopted the integrated living schedule (ILS) plan proposed by NRC Generic Letter No. 85-07. They have submitted a Technical Specification Change Request (TSCR) No. 170, dated July 13, 1987, requesting adoption of the ILS into the TMI-1 operating license. The proposed ILS is consistent with Topical 042.

During the last year, the licensee revised its corporate structure to provide a vice president dedicated to Planning and Safety Review. Incorporated into this organization is the Licensing Department and Long Range Planning for TMI-1 and Oyster Creek, each having dedicated staffs. It appears that the licensee has effectively unified planning and prioritization of regulatory and safety issues under the direction of a single vice president who is corporate based.

The inspector also noted that this Topical Report was complete in that it has all the issues for which there were inspector-known licensee commitments for Cycle 7R. This included such things as certain modifications in conjunction with Regulatory Guide (RG) 1.97 and Inservice Testing commitments dealing with the need for additional pump/valve instrumentation.

The 7R outage is scheduled to start July 1, 1987, for nine weeks, but this is subject to change depending on plant performance during 1986/1987 and the need for power in the summer months. The length of the outage may be shortened depending on progress already started for RG 1.97 modifications not needing a plant shutdown. The planning also includes contingencies for unforeseen work, such as in response to adverse inservice inspection results. Contingencies for person-rem exposure and radwaste generation were also noted.

Also, the inspector noted licensee initiative to schedule modification work for 7R that would enhance the reliability of the integrated control system (ICS). This was in response to the Babcock & Wilcox (B&W) Owners Group's System Performance Improvement Program, which is a part of the NRC staff B&W Reassessment. The NRC staff is still reviewing the owners' group effort.

5.5 Technical Support Assessment

In response to the latest SALP, the licensee agreed with a SALP board recommendation to reassess the technical support functional area. In July 1987, the inspector received a briefing on how the licensee was to proceed with the reassessment. While at the corporate office, the inspector obtained a status on the effort with the task group leader.

In accordance with the Institute of Nuclear Power Operations (INPO) guidelines the technical support area includes a number of major sub-areas in addition to engineering support (provided by the Technical Functions Division and the Plant Engineering Department). These additional areas include: inservice inspection and testing, surveillance, maintenance, and plant analysis. The initial phase of the reassessment was to survey selected site and corporate personnel by both a questionnaire and, in some cases, by actual interview. These responses were completed, being tabulated, and preliminary analysis is just starting. Issues for follow-up need to be identified and presented to licensee management for review. Root cause analysis is expected to follow this review with a definitive action plan for corrective action to be formulated along with monitoring to assure effective results.

The inspector noted that an uncertainty existed on when the above-noted process would be completed, including the initiation of corrective action and monitoring for results. It appeared to the inspector that reasonable progress was made by the licensee on this effort, but the inspector also noted that the licensee would be working on this reassessment well into the next SALP period. Accordingly, since this reassessment is a left-over issue from the last SALP to enhance performance, this area is unresolved pending licensee identification of corrective actions and the initiation of monitoring for effective results and pending subsequent Region I review (289/87-19-03).

Also, the licensee's response, dated April 1, 1987, to the last SALP indicated that Technical Functions (TF) will initiate a program of sampling reviews to assure that "replacement-in-kind" parts were being handled properly. As of the end of this inspection period, no real progress occurred on this item. The licensing department initiated Licensing Action Item (LAI) No. 87-9122 early this year at the time of the SALP response (April 1987).

Related to this area and based on discussions with the QA Audits Supervisor, a QA audit (No. 87-015) is in progress in the plant engineering area; and, in particular, focus is to occur in the "replacement-in-kind" area.

Accordingly, this area is unresolved pending completion of the TF review and subsequent NRC Region I review (289/87-19-04).

5.6 Safety Evaluations

The inspector reviewed selected licensee safety evaluations (SE's) for facility modifications and corporate procedure changes to assess compliance with 10 CFR 50.59 and related licensee procedure controls to implement these requirements.

The inspector reviewed selected sections of the following SE's.

Modifications

-- SE No. 115302-022, Revision 0, March 4, 1987, and Revision 1, May 15, 1987, "River Water Pumps Lubrication System, Reclassification from ITS to NITS"

-- SE No. 000533-001, Revision 0, December 29, 1986, and Revision 1, January 30, 1987, "The Addition of Unions to Pressure Instrumentation Piping on Decay Heat Service Cooler DC-C-2A"

-- SE No. 419628-001, Revision 0, April 10, 1987, and Revision 1, April 13, 1987, "Fire Service Water Connection for the Instrument Calibration Facility"

-- SE No. 418051-001, Revision 0, October 4, 1986, and Revision 1 April 16, 1987, "Extension of TMI-1 Microwave Perimeter Intrusion Detection System"

-- SE No. 413916-001, Revision 0, July 6, 1987 "WDL-V535 Low Level Interlock"

-- SE No. 412484-001, Revision 0, August 19, 1987, "Installation of Local Flow Measurement Instrumentation (for Screen House/Control Building Heating and Ventilation (H&V) System)

-- SE No. 412458-003, Revision 0, August 17, 1987, "CIV (Containment Isolation Valve) Replacement"

-- SE No. 115302-024, Revision 0, March 11, 1987, "TMI-1 250/125 V d.c. Fuse Changes"

-- SE No. 000231-003, Revision 0, January 23, 1987, "Installation of Isolation Valve for WDL-7A/B"

-- SE No. 000852-001, Revision 2, July 10, 1987, "Isolation of Back-Up Instrument Air to MS [Main Steam] and EFW [Emergency Feedwater] System Components"

-- SE No. 412384-013, Revision 0, September 14, 1987, "Reactor Coolant Pump Trip Modification"

-- SE No. TI-412525-001, Revision 0, "Two Hour Back-Up Instrument Air Charging Compressor"

Corporate Procedure Changes

-- SE No. 945100-008, Revision 0, December 24, 1986, and Revision 2-00 to 5000-ADM-7312.01, GPUN Drawings (EP-002)

-- SE No. 084001-S004, Revision 0, June 5, 1987, and Revision 2-00 to (SP-004) 5000-ADM-7335.04, "Test Closeout," and Revision 2-00 to (SP-001) 5000-ADM-7335.01, "Startup and Test Program and Test Requirements"

-- SE No. 945100-001, Revision 2, March 27, 1987, to (EP-027) 1000-ADM-1218.03, "Plant Procedure Review"

-- SE No. 945100-002, Revision 2, March 27, 1987, and Revision 3, June 16, 1987, "Safety Review Process" (EP-016)

-- SE for Revision 3 to 1000-ADM-1291.01, September 20, 1987, "Procedure for Nuclear Safety and Environmental Impact Review and Approval Documents"

Other Documents

-- Computer Index of SE's Search issued for 1987 (127 items listed) for modification, procedure changes, and TSCR's

-- Technical Data Report (TDR), Revision 0, February 21, 1986, and Revision 1, December 12, 1986, "Safety-Related Pump Operation Without Clean Water Bearing Lubrication"

For modifications, the SE's were reasonably thorough and, in some instances, quite extensive and detailed. Invariably, the licensee's two-step process (Form 1 and 2) was fully invoked in that the second form with the traditional 10 CFR 50.59 unreviewed safety questions were addressed. In accordance with the licensee's procedural controls for SE's (Technical Functions Procedure EP-016), the SE narratives were quite detailed in addressing applicable safety-grade criteria. The inspector noted that, in certain instances, the independent safety reviewers challenged the SE's and that resulted in subsequent revisions.

For corporate procedure changes, the inspector noted no significant discrepancies.

No violations were identified.

5.7 Corporate Inspection Summary

In general, the licensee corporate personnel were adequately working on or addressing the open issues discussed above. For the areas reviewed, the licensee programs were supporting safe operation at TMI-1. A target completion date needs to be identified by the licensee for the technical support reassessment. Within the scope of this review, no conditions adverse to safety or regulatory requirements were identified.

6. Control Room Environment

6.1 Background/Scope of Review

The inspector reviewed the conditions that exist in the control room which affect the conduct of the licensed operators. This review was accomplished under the guidance given in Region I Temporary Instruction No. RI-87-01, issued January 16, 1987. The purpose of this review was to assure that no conditions exist in the control room that would prevent safe operation of the plant or could allow distractions that would prevent full attention of licensed operators in performing their duties.

The inspector reviewed the following documents in accomplishing this review:

-- 10 CFR-50.54, Conditions of License;

-- Regulatory Guide (RG) 1.114, "Guidance on Being an Operator at the Controls of a Nuclear Power Plant;"

-- IE Circular 81-02, "Performance of NRC-Licensed Individuals While on Duty;" and,

-- Director, Division of Reactor Projects, NRC internal memorandum dated January 4, 1985, to resident inspectors.

6.2 Findings/Conclusions

The inspector reviewed the following areas related to the control room environment during this review with the results discussed below. These areas are normally reviewed on a daily basis through frequent routine tours of the control room and discussions with operators.

6.2.1 Licensed Operator Professionalism

Licensed operators generally conduct their duties with a good sense of pride and discipline at TMI-1. There are no major distractions that exist in the control room; no radios or televisions are present, nor are they permitted. The operators have never been observed reading extraneous material or engaging in activities that were not conducive to safe plant operations. When questioned by NRC inspectors, the operators generally provide complete and accurate responses. Plant status is displayed on a status board and current plant abnormal conditions are displayed on a monitor (or CRT) in full and easy view of plant operators. Operators are responsive to plant annunciators and respond appropriately.

6.2.2 Noise Control

The conduct of shift business that must be accomplished in the control room; e.g., discussions with the shift foreman for the conduct of surveillances and maintenance, is carried out in an area of the control room that does not affect the operators performance of routine duties. The noise level in the control room is generally kept to an acceptable level.

6.2.3 Control Room Access

Access to the control room is controlled by the shift supervisor (SS) or shift foreman (SF). A physical barrier exists to separate the "control room proper" (CRP) from the routine conduct of business area. Operations personnel who normally tour the control room and shift personnel usually enter the CRP without permission. Other personnel; e.g., maintenance, surveillance, quality assurance/quality control (QA/QC) monitors, are required to request permission from the SS/SF as noted by a prominently posted sign. This practice is routinely noted by the inspectors to be observed. The number of people actually working in the CRP or conducting official business is generally kept to minimum levels. During certain major evolutions; i.e., planned startups and shutdowns, larger numbers of operations and management personnel, along with oversight personnel such as QA/QC, are routinely present. These situations are necessary and the inspectors note that they have not detracted from plant operations control.

6.2.4 Control Room Appearance

The control room is generally kept clean and orderly. Adequate space is provided for operators to use procedures/manuals for routine evolutions. Eating activities are permitted, but the inspector has not observed that this activity was detrimental to plant operations. Eating and drinking are not permitted directly over control room panels. Equipment normally used in the control room is stored adequately. Overall, there usually is an appearance of order in the control room.

Also, the licensee continues to make progress in achieving a "black-board" main annunciator panel (that is, no annunciator normally lighted). The licensee processed certain design changes to eliminate normally lighted annunciators. The only one on the main board remaining are two annunciators indicating a battery ground. The "black-board" concept enhances operator attention to truly off-normal occurrences.

6.3 Summary

In general, the overall control room environment is quiet, professional, and businesslike. There are few distractions for the operators, access is properly controlled, and noise levels are acceptable. Overall management actions are conducive to the current state of this environment. Temporary Instruction RI-87-01 is closed.

7. Storage of Transient Equipment in Safety-Related Areas

7.1 Background/Scope of Review

The inspector reviewed the storage of transient equipment in safety-related areas to assure no adverse impact on safety-related equipment in case of an industrial accident and/or seismic event. This review was accomplished under the guidance of Region I Temporary Instruction (TI) No. RI-87-03, dated March 5, 1987, to resident inspectors. Transient equipment includes: dollies; blocks and tackles; filled or unfilled gas bottles; heavy equipment (stationary or on rollers); and temporary office spaces; along with housed furniture, cabinets, etc.

The purpose of this review was to:

-- ascertain the status of licensee administrative controls (or other type of facility procedures) in the subject area;

-- determine the proper implementation of administrative controls (or other type of facility procedures) for the subject area;

-- identify if deficiencies exist independent of whether or not facility procedures cover the subject area; and,

-- where deficiencies exist, assess the licensee corrective action process with respect to the applicable NRC Information Notice.

The inspector reviewed the following documents:

-- 10 CFR 50, Appendix A, Criteria 2 and 4;

-- NRC IN 80-21, dated May 16, 1980;

-- Maintenance Procedure (MP) 1401-18, "Equipment Storage Inside Class 1 Buildings;" and,

- MP 1440-Y-3, "Scaffold Inspection."

Selected areas of the following safety-related buildings were inspected: reactor building (on previous inspections); auxiliary building; fuel handling building, intermediate building; diesel generator building; and, control building.

7.2 Findings/Conclusions

The resident inspectors have reviewed this area routinely since TMI-1 restart on October 3, 1985. Also, they have more extensively reviewed the established procedural controls for adequacy and for proper procedural adherence during the following inspections: Nos. 50-289/85-19, 85-21, 85-22, and 87-09. The more focused reviews have occurred primarily during the licensee's transition from cold shutdown (outages) to power operations. These inspections have found the program to be generally adequate with only minor implementation discrepancies.

During this inspection, the inspectors noted no conditions adverse to safety or regulatory requirements during the routine inspection of safety-related building spaces. This indicated continued adherence to established controls. Unrestrained equipment without rollers was located and positioned on the floor at a safe distance so as not to adversely affect safety-related equipment if it fell over. Equipment on rollers was restrained with wire rope. Scaffolding was rigid and restrained to the building walls, using wire rope and cement anchors. Loose equipment on top of platforms or brackets was minimized and was assumed to fall and, therefore, kept at a safe distance from the safety-related equipment.

Based on a limited review of licensing records, the inspector concluded that procedural controls in this area were upgraded in response to the subject NRC Information Notice.

7.3 Transient Equipment Storage Summary

The licensee's procedural controls for the storage of transient equipment (as defined above) is adequate and these controls are, in general, properly implemented.

8.0 Licensee Event Reports (LER's)

The inspector reviewed the LER's listed below, which were submitted to the NRC Region I office pursuant to 10 CFR 50.73. Based on a review of these LER's, the inspector determined that corrective actions discussed in the report were appropriate and that there were no generic issues.

-- LER 87-008, dated October 16, 1987, for an event on September 16, 1987, "Reactor Trip From Turbine Trip Due to High Moisture Separator Level." The high moisture separator level was found to be caused by a defective moisture separator drain tank level control valve, which allowed the moisture separator level to increase to the turbine trip level. A high level alarm in the drain tank failed to function. The root cause of this event was equipment malfunction (level control valve). Licensee corrective action included improving the preventive maintenance on the level switches and level control valves for the moisture separator drain system. Immediate and long-term planned corrective action for this event appear adequate.

The inspector had no other concerns on this event, which was reviewed in NRC Inspection Report No. 50-289/87-17.

-- LER 87-009, dated October 26, 1987, for an event on September 27, 1987, "Release with Liquid Release Monitor (RM-L6) in Defeat Due to Personnel Error." An effluent radiation monitor (RM-L6) interlock to assure closure of the tank release discharge valve was inoperable during a release. The LER describes several personnel errors on the part of maintenance and operations staffs in assuring the interlock was enabled. However, procedure enhancements were also planned to verify and control the proper positioning of the interlock defeat/enable switches in the release sequence. This is a licensee-identified violation; and, in accordance with the NRC's Enforcement Policy, no citation will be issued.

This event was reviewed in NRC Inspection Report No. 50-289/87-17 (Unresolved Item No. 289/87-17-01). By issuance of this LER, the licensee resolved the outstanding issues listed for this item. By paragraph 4.3.4, Region I reviewed this item for implications to the IVP. However, the LER listed procedure enhancements are not specific. Accordingly, this item (289/87-17-01) remains open pending completion of licensee action as stated in LER 87-009 and pending subsequent NRC:Region I review.

9. Licensee Action on Previous Findings

9.1 Closed) Unresolved Item 289/84-16-01: Ventilation Balance Problems in the Auxiliary and Fueling Handling Buildings.

This item was opered due to problems experienced when airborne radioactivity releases were made in the auxiliary/fuel handling buildings (A/FHB) during routine operations. The licensee contracted an outside engineering firm to test and properly balance the ventilation flows from the different areas of the A/FHB. With this balanced condition, any airborne releases would be properly channelled through normal filtered and monitored ventilation paths.

The licensee completed this test and balancing in July of 1987. Several components in the system, mainly dampers and flow control devices were found out of adjustment or incapable of functioning properly. These items have been repaired.

The inspectors have routinely toured areas of the A/FHB in recent months since completion of the balancing. The inspectors observed negative pressures existing in areas/cubicles of the auxiliary building where airborne releases have occurred in the past. The inspector reviewed the "as-found" and final flow data from the contractor's report. Several areas were initially significantly out-of-design flow rates. The flows, in most of the areas, have been adjusted to generally be much closer to design values.

The licensee is in the process of formally issuing an internal report on the problem and may make additional modifications to the ventilation systems based on their final review.

The inspector concluded that ventilation in the auxiliary and fuel handling building has been significantly improved over previous conditions. The inspector had no other safety concerns and this item is closed.

9.2 (Closed) Unresolved Item (289/85-27-08): Verification of Correct Operating Activities

Previous NRC Inspection Report (IR) Nos. 50-289/82-16 and 83-02 previously closed TMI Task Action Plan (TAP) Item No. I.C.6, "Verification of Current Operating Activities," and related open issues. NRC Inspection Report No. 50-289/85-27 reopened the issue associated with Item No. I.C.6 because of questions on the scope of program application and a somewhat confusing record on what were licensee commitments in this area.

The licensee's letter of April 29, 1987, in response to IR No. 85-27 was reviewed in IR No. 86-17 and the letter was found to be unacceptable in addressing the elements of TAP Item No. I.C.6. The licensee's letter of June 3, 1987, was in response to NRC concerns addressed in IR No. 86-17. This latest letter is considered an acceptable response. The licensee's independent verification program (IVP), as embodied in these two licensee letters, was reviewed in Section 4 of this report.

The licensee's letter of June 3, 1987, made it clear that any additional commitments or scope expansion would have to be justified by substantial safety reasons using the backfit process (10 CFR 50.109).

Also, this letter made two statements with which the inspector did not agree. First, the licensee stated that: "We feel that our commitments as well as the scope of the independent verification program are clear, especially now that the procedures specify verification at the component level. We are not aware of any inconsistencies." The following is an example on where commitments are not clear and a minor inconsistency still existed.

In response to NRC staff questions (Nos. 21 and 22) as documented in TMI-1 Restart Report, Supplement 1, Part 2, the licensee states: "Post-maintenance valve lineup of safety-related systems will be compared to system flow diagrams by two independent operator reviews of the switching orders prior to removal of safety tags to ensure proper restoration of the system to operability;" and "Following surveillance tests or special operations on ESAS and EFW systems, two independent valve and breaker lineups will be conducted within the boundary of the system affected by the tests or special operations to provide assurance that the system is returned to full operational status." Reviewing these later two licensee statements, the inspector finds for the activities of making something inoperable and then the restoration to normal by a surveillance or a maintenance activity: (1) there are two different scopes; one statement says safety related and the other statement says ESAS and EFW; (2) one method is comparison of a lineup by two operators to flow diagrams; the other method is two independent valve and breaker lineups within the boundary of the system affected; and, (3) critical valves (currently defined) were not apparently defined in relation to 10 CFR 100 release criteria in the hearing record.

These confusing items, although minor, remain in AP 1001A, Revision 13, effective June 26, 1987, "Procedure Review and Approval," Enclosure 4. "Special Temporary Procedure (STP) Instructions," Line 3, which states: "The STP must contain a step which requires an independent valve and/or switch position verification check be performed within the boundary of [ESAS and EFW] system(s), component(s), channel(s), etc. affected by the STP prior to returning [the same] to service." This statement is not clear and apparently is inconsistent with the critical valve philosophy of AP 1067. It should also be noted that AP 1001A is not referenced in the AP 1067 as being embodied in the IVP program. Accordingly, it is not clear what requirements for IVP the licensee intended to be incorporated into an STP. A licensee representative agreed to change AP 1001A to make it consistent with AP 1067.

Secondly, the same licensee letter stated that: "The TMI-1 Independent Verification Program was intentionally limited to those systems/components for which the risk and consequences of their misposition could result in a significant potential for off-site dose. This is consistent with NRC Information Notice (IN) 84-51, concerning independent verification." The inspector disagrees on the consistency of NRC IN 84-51 being limited to significant potential of off-site dose. The critical valve concept in relation to 10 CFR 100 release is not mentioned in IN 84-52. Further, the IN implies or recommends that complete safety-related system valve lineups be independently verified when coming out of a major outage. The licensee's program falls short of this recommendation. However, no adverse safety impact is noted as a result.

None of these disagreements affect the resolution of this unresolved item.

Accordingly, the unresolved item is closed since the licensee provided the required responses as noted above.

9.3 (Closed) Unresolved Item (289/85-28-01): Independent Verification of Containment Penetration Test-Tee Caps

The licensee's independent verification program (IVP) overall was reviewed in Section 4. Specific procedure deficiencies identified as a part of the items were verified to be corrected by this review. Essentially, the test-tee caps are independently verified to be properly installed in accordance with the IVP (AP 1067) and as required by applicable operation and surveillance procedures, especially those involving containment integrity. Applicable surveillance records and inspector independent verification confirmed proper implementation of the IVP.

This item is considered closed.

9.4 <u>(Closed) Unresolved Item (289/86-06-05)</u>: <u>Station Vital Battery Testing</u>.

The adequacy of the licensee's vital battery test program was questioned during review of the test results after replacement of the "A" vital battery bank in March 1986. The issue concerned the adequacy of the licensee's capacity test performed on a refueling outage basis (per Technical Specification (TS) 4.6.2.d) in lieu of a duty-cycle load test specified in Institute of Electrical and Electronic Engineers (IEEE) Standard 450 - 1980 (not a licensee commitment). A duty-cycle load test had been performed by the manufacturer on selected individual battery cells prior to installation. A periodic duty-cycle load test that attempts to simulate the actual demand on the battery during worst case loading is not performed by the licensee once the battery is installed. However, in accordance with TS 4.6.2.d, a capacity test (two hour constant current discharge per SP 1303-11.11) is performed during each refueling outage.

The licensee subsequently re-evaluated the acceptability of their battery test method as satisfactory based on the following considerations.

-- The presently performed two hour constant rate discharge test is similar to the design basis duty-cycle load profile. The design basis load profile (amperes versus time) has some higher short duration loads than the constant rate test/load. The cell sizing is determined by the amount of energy (ampere- hours) needed to be expended or discharged.

-- Duty-cycle loads, which exceed the battery's two-hour rating, occur early in the duty-cycle when the battery is essentially still fully charged and these loads do not result in battery voltages approaching minimum design voltage. Since the duty-cycle load profile is similar to a constant current-load profile, the voltage profile recorded for either type of discharge will also be similar.

-- The above statements are shown to be true by actual test results from the manufacturer on a worst-case individual cell basis.

-- Cell-to-cell inter-connection resistance could adversely affect the above-noted test results. The inter-cell and inter-tier connections on each station battery cell are measured. Inter-cell and inter-tier connections are checked at each plant refueling period. Connection resistance measurements must be with in 20 percent of baseline data.

The above evaluation was considered adequate to resolve the inspector's concerns about the adequacy of the licensee's battery test program and this item is considered closed.

9.5 (Open) Unresolved Item (289/86-19-01: Review Procedures Compliance Task Group Corrective Actions..

The inspector reviewed the status of the long-term corrective actions which were recommended by the Procedures Compliance Task Group (PCTG). The PCTG had formulated seven short-term and seven long-term corrective actions to resolve past procedure compliance problems. Short-term corrective actions have been completed as previously discussed in NRC Inspection Report No. 50-289/86-19. These short-term actions were generally the issuance of internal memoranda and reminding individuals of their responsibility to adhere to procedures. Most long-term corrective actions are still pending licensee evaluation and implementation.

Formal procedure guidelines to implement a consistent policy on procedure adherence has been formulated and is awaiting final approval. The "procedure owner" program is a part of this administrative procedure change (1000-ADM-1218.01).

Another initiative, development of procedure writing guidelines and an associated training program is awaiting funding. Other initiatives such as the procedure improvement "team" concept, developing faster change mechanisms and developing "target" levels for QA deficiencies are still in the evaluation process.

The inspector concluded that reasonable progress has been made in this area. The inspectors will review these initiatives as they are completed or resolved and become a part of the licensee procedure control program.

9.6 (Open) Unresolved (289/87-17-01): Inoperable Radiation Effluent Monitor Interlock (LER 87-009)

See section 8 for details.

9.7 (Closed) Region I Temporary Instruction (No. 289/87-TI-01): Control Room Environment.

See section 6 for details.

9.8 (Closed) Region I Temporary Instruction (No. 289/87-TI-03): Storage of Transient Equipment in Safety-Related Areas.

See section 7 for details.

10. Exit Interview

The inspectors discussed the inspection scope and findings with licensee management at interim interviews on October 16, 1987 (corporate inspection), and on October 20, 1987 (Independent Verification Program), and a final exit interview conducted November 2, 1987. Senior licensee personnel attending the final exit meeting included the following:

G. Broughton, Operations and Maintenance Director, TMI-1
J. Colitz, Plant Engineering Director, TMI-1
K. Harkless, Safety Review Engineer, TMI-1
H. Hukill, Director, TMI-1
C. Incorvati, TMI-1 Audit Manager
M. Nelson, Manager, Nuclear Safety, TMI-1
H. Shipman, Operations Engineer, TMI-1
D. Shovlin, Plant Material Director
C. Smyth, TMI-1 Licensing Manager
M. Snyder, Preventive Maintenance Director

The inspection results as discussed at the meeting are summarized in the cover page of the inspection report. Licensee representatives did not indicate that any of the subjects discussed contained proprietary or safeguards information.

Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable, violations, or deviations. Unresolved items discussed during the exit meeting are addressed in Sections 5 and 9.

ATTACHMENT 1

NRC INSPECTION REPORT
NO. 50-289/87-19

ACTIVITIES REVIEWED

Plant Operations

Control room operations during regular and back shift hours, including frequent observation of activities in progress and periodic reviews of selected sections of the shift foreman's log and control room operator's log and selected sections of other control room daily logs

Areas outside the control room

Selected licensee planning meetings

Shift Turnover on October 28, 1987

Emergency Feedwater Standby Status as of October 29, 1987

Emergency Diesel Generator Standby Status as of October 7, 1987

Control Room Environment

During this inspection period, the inspectors conducted direct inspections during the following back shift hours.

Date	Time
10/4-5/87	11:30 p.m. - 1:00 a.m.
10/10/87	8:30 a.m. - 10:30 a.m.
10/11/87	10:00 a.m. - 12:00 Noon
10/28/87	6:00 a.m. - 7:00 a.m.
10/30/87	5:30 a.m. - 6:30 a.m.
10/31/87	8:00 a.m. - 9:30 a.m.

Maintenance

Reactor Protection System Breaker Replacement (PM E-36) on various dates throughout the inspection period

Storage of Transient Equipment in Safety-Related Areas

Surveillance

Reactor Projection System Surveillance (SP 1303-4.1) at various dates throughout the inspection period

Differential Pressure Switch Calibration, NR-DPS-138 (per IC-15) on October 15, 1987

Reactor Coolant System Leak Rate (SP 1301-1) on November 1, 1987

Reactor Coolant System (RCS) Leak Rate

The inspector selectively reviewed RCS leak rate data for the past inspection period. The inspector independently calculated certain RCS leak rate data reviewed using licensee input data and a generic NRC "BASIC" computer program "RCSLK9" as specified in NUREG 1107. Licensee (L) and NRC (N) data are tabulated below.

TABLE

RCS LEAK RATE DATA
All Values GPM

DATE/TIME DURATION	L_G	N_G	(NUREG 1107) N_U	CORRECTED N_U	L_U
10/5/87 08:27:13 2 Hours	0.6416	0.64	-0.25	-0.15	-0.1440
10/8/87 00:30:13 2 Hours	1.3396	1.34	-0.13	-0.03	-0.0217
10/8/87 07:42:26 2 Hours	1.2622	1.26	-0.01	0.09	0.0933
10/8/87 16:33:37 2 Hours	1.6475	1.64	-0.10	0.00	0.0077
10/14/87 00:37:21 2 Hours	0.5019	0.50	-0.13	-0.03	-0.0210
10/22/87 15:49:47 2 Hours	0.0679	0.07	-0.42	-0.32	-0.0326
10/26/87 16:34:13 2 Hours	0.7946	0.79	-0.01	0.09	0.0934

DATE/TIME DURATION	L_G	N_G	(NUREG 1107) N_U	CORRECTED N_U	L_U
10/28/87 16:54:01 2 Hours	0.8532	0.85	-0.09	0.01	0.0159
10/31/87 07:08:30 2 Hours	0.3960	0.40	-0.02	0.00	0.0031
11/1/87 16:13:41 2 Hours	1.1851	1.18	-0.09	0.01	0.209

G = Identified gross leakage U = Unidentified leakage
L = Licensee calculated N - NRC calculated

Columns 2 and 3, 5 and 6 correlate $\pm$ 0.2 gpm in accordance with NUREG 1107. (N_U is corrected by adding 0.1044 gpm to the NUREG 1107 N_U due to total purge flow through the No. 3 seal from RCP's.