U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-387/84-14
50-388/84-16

Docket No. 50-387 (CAT C)
50-388 (CAT B2)

License No. NPF-14
NPF-22 Priority -- Category --

Licensee: Pennsylvania Power and Light Company
2 North Ninth Street
Allentown, Pennsylvania 18101

Facility Name: Susquehanna Steam Electric Station

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: April 1 - May 7, 1984

Inspectors: Richard J Jacobs — May 9, 1984
R. Jacobs, Senior Resident Inspector — date

Loren R. Plisco — May 9, 1984
L. Plisco, Resident Inspector — date

Clifford J. Anderson for FP — 5/14/84
F. Paulitz, Reactor Engineer — date

Approved by: Ebe McCabe — 5/14/84
Ebe C. McCabe, Chief, Reactor Projects Section 1C, DPRP — date

Inspection Summary:

Areas Inspected: Routine resident inspection (U-1 107 hrs., U-2 190 hrs.) of plant operations, equipment readiness, license conditions, licensee events, open items, TMI action items, maintenance, surveillances, and fuel loading activities.

Results: Unit 2 license conditions for initial criticality were satisfactorily completed. Unit 1 RCIC overspeeding problem needs additional attention. (Detail 5.1).

One violation was found: local leak rate test valves in Unit 1 were closed instead of closed and locked as required by the system P&ID and administrative procedures. (Detail 3.2).

Region I Form 12
(Rev. February 1982)

DETAILS

1.0 Persons Contacted

Pennsylvania Power and Light Company

G. Butler, I&C Supervisor
H. Keiser, Superintendent of Plant
J. Maderias, Supervisor Nuclear Records
L. O'Neil, Maintenance Supervisor
H. Palmer, Supervisor of Operations
D. Thompson, Assistant Superintendent of Plant

Other members of the plant staff were also contacted.

2.0 Followup on Previous Inspection Findings

2.1 (Closed) Construction Deficiency Report (388/81-00-10) Lack of Separation in PGCC Cables.

Plant Modification Record (PMR) 83-637 was performed to correct the deficiency involving the lack of required special conduit separation for safety-related electrical circuits to the HPCI and RCIC inboard steam isolation valves. The modification consisted of rerouting the HPCI cable through a new conduit in order to insure cable separation is maintained. The modification was completed on April 16, 1984.

The inspector reviewed the completed design change package and walked down portions of the installation. No discrepancies were noted.

2.2 (Closed) Construction Deficiency Report (388/83-00-07) Potential Scram Discharge Volume (SDV) Waterhammer.

This item was reviewed during NRC Inspection 50-388/84-08 and remained open pending rework of supports on the SDV vent and drain lines. The rework has been completed. The inspector reviewed PMR 84-3064 and Construction Work Order (CWO) C44170 which documented completion of the rework. The inspector also examined portions of the rework. No discrepancies were noted. The licensee issued the final report of this construction deficiency on April 19, 1984.

2.3 (Closed) Construction Deficiency Report (388/83-00-17) Improper Relief Valve Settings, Design Pressures and Temperatures for Safety Related Piping.

The design aspects of this item were previously reviewed by a Region-based inspector during inspections 50-387/83-25, 50-388/83-24 and 50-387/84-03, 50-388/84-04. Additionally, this item was discussed at a meeting in NRC Region 1 on November 21, 1983. This inspection focused on the implementation aspects of licensee's corrective actions.

By letter dated April 19, 1984, the licensee submitted the final report on this construction deficiency which involved improper relief valve settings, design pressure and temperature inputs on Unit 2 piping systems. To confirm the adequacy of safety related piping at Susquehanna, PP&L directed Bechtel to perform a complete review of all Q-listed piping in specification M-199. In addition Teledyne Engineering Services conducted an independent design review. As a result of the Bechtel review, 245 discrepancies in design pressure/temperature and relief valve settings were discovered. Teledyne identified 27 items requiring correction. The reviews identified no piping which required replacement due to the inadequacy of the design inputs. The only hardware modifications involved the replacement of Residual Heat Removal (RHR) seal water pump coolers and resetting of Containment Instrument Gas header relief valves. Other corrective actions involved reanalyzing piping for higher design temperatures and the performance of hydrostatic tests to recertify piping for higher design pressures.

The inspector discussed this item with licensee engineers and reviewed the following documents:

-- Teledyne Engineering Services Technical Report No. 6078-1 dated March 15, 1984 including selected audit findings.

-- MCAR 1-86, Bechtel "Final Report on Piping Design Pressures and Temperatures" dated March 1984.

-- Study Calculation No. 5505 for H_2/O_2 Analyzer System lines for HCB-126 and HCB-154.

-- Study Calculation No. 8197 Emergency Service Water (ESW) line HRC-126, Core Spray Room Cooler Return.

-- TP-054-013, Unit 2 Reactor Building ESW Loop A Hydrostatic Test package.

-- TP-054-011, ESW Loop A Piping Hydro (HRC piping).

-- Hydrostatic Test Reports No. 4316 A and B for Core Spray System HBB-204 piping.

-- Construction Work Order C44114 which documents the installation of the Unit 2 RHR seal water coolers.

-- Various Design Change Notices (DCN) to Project Specification M-199.

-- Bechtel letter, F. Titus to T. Crimmins, PP&L dated January 23, 1984 which documented Bechtel's position that specific evaluations of containment piping systems and supports for the effects of Post LOCA environmental temperatures are not required.

Inspector review of the above documents identified no discrepancies other than minor administrative deficiencies which were corrected.

2.4 (Closed) Construction Deficiency Report (388/83-00-20) Control Rod Drive (CRD) Insert/Withdraw Line Supports.

Corrective actions for this deficiency involved modification of the outer reactor pedestal supports to provide 3-way restraint for the insert/withdraw lines. (See Inspection Report 50-387/84-07; 50-388/84-08). Subsequent review by NISCO/Teledyne and Bechtel identified a number of additional discrepancies where the pipe support installation did not agree with the system stress report and hence, the supports required modification.

The inspector reviewed NCR's 84-223 and 84-485 (which document the above discrepancies) and Plant Modification Record (PMR) 84-3058. The corrective action involved replacement of "Z" clips with guides on 24 ganged pipe supports and changing some guides to rigid clamps and some rigid clamps to guides on 4 other ganged supports. The inspector examined several supports and found no discrepancies with the implementation of the above PMR. However, on support 2S08, the inspector noted that a guide was installed where a "Z" clip was specified on drawings M164-201, Sheet 2, Revision 3 and VCRH-1091-201, Sheet 2, Revision 7. When informed of this discrepancy, PP&L and Bechtel engineerings inspected all supports affected by PMR 84-3058 to determine other discrepancies with "Z" clip locations. None were found. The inspector also examined about 10 supports and found no other discrepancies.

The licensee evaluated the "Z" clip discrepancy against the stress report and determined that the "Z" clip should have been installed. A new "Z" clip was installed under Work Authorization (WA) V43193. In response to the inspectors concern about the potential for other discrepancies with the as built configuration of the CRD system, the licensee provided the following information. An as-built field verification of the system was performed in March 1983 in accordance with ASME code requirements. This verification was performed using the Bechtel "VP" drawings (drawing VCRH-1091-2 is a Bechtel VP drawing). An examination of other supports affected by PMR 84-3058 (about 90% of all I/W line supports) revealed no other discrepancies. No work documentation was found which authorized replacement of the "Z" clip in question. This problem is not an extension of the other CRD I/W line problems previously found. Hence, it appears that this discrepancy was an isolated occurrence.

2.5 (Closed) Inspector Followup Item (388/83-32-05) Plastic Screws and Washers Found in Termination Cabinets.

On January 19, 1984, during preoperational testing which involved a LOCA signal on Unit 2 with offsite power available, certain auxiliary relays did not energize as required. The problem was traced to the use of plastic screws and washers (at terminals in termination cabinets 2TC623 and 2TC613) which broke continuity in the circuits.

The licensee replaced the affected screws and washers, verified continuity, and continued the testing. A Significant Operating Occurrence Report (SOOR) was issued to document the event and Nonconformance Report 84-143 was issued to identify and disposition the nonconforming condition. The licensee conducted a review of previous work documentation, and could not determine when the screws and washers were installed. One work authorization performed in November 1982 isolated the cables, but it was properly restored based on Quality Control Inspection records. No other cases of this type were found in the investigation. The licensee conducted training for the electrical maintenance department concerning the event and the required system control procedures.

The inspector reviewed the NCR and the attendance sheets for the training performed. This item appears to have been an isolated case and present procedural controls and training on those procedures should prevent recurrence.

2.6 <u>(Closed) Construction Deficiency Report (388/84-00-01) Lack of Isolation Capability for SPDS Signal Isolation Devices.</u>

The class 1E power source to the Unit 2 HPCI pump flow SPDS isolation device was disconnected and replaced with a non-1E power source. The work was performed under Plant Modification Record (PMR) 84-3048. The inspector reviewed the completed work documentation and no deficiencies were noted.

The remainder of the licensee's corrective action was previously reviewed in NRC Combined Inspection Report 50-387/84-07 and 50-388/84-08.

2.7 <u>(Closed) Construction Deficiency Report (388/83-00-15) Isolation of the Nitrogen Makeup System.</u>

A modification performed under Design Change Package (DCP) 83-745 rerouted the drywell and suppression pool nitrogen makeup lines to spare penetrations and installed two divisionalized isolation valves on each line. Each valve is operated by a dedicated handswitch on the main control board.

The inspector reviewed the design change package and walked down portions of the new installation. No unacceptable conditions were identified.

A proposed Technical Specification change was submitted April 10, 1984 (PLA-2173) to ensure the Technical Specifications properly reflect the installation of the modifications to the Nitrogen makeup system, since two new containment isolation valves were added.

2.8 <u>(Closed) Inspector Followup Item (388/84-08-01) RHR System Vibration Problems.</u>

One of the corrective actions from Construction Deficiency (388/81-00-33) involved issuing Emergency Operating Procedure, "Plant Shutdown From Outside Control Room", EP-200-009 which would direct that RHR system flow be maintained at about 10,000 gpm to prevent RHR system vibration problems. The inspector verified that EP-200-009 Revision 0 contains this requirement.

2.9 <u>(Closed) IE Circular 78-11, Recirculation M-G Set Overspeed Stops (387/78-CI-11).</u>

Surveillance procedure SI-164-305, Revision 0, 18 Month Calibration of Recirc. M-G Sets A & B Mechanical and Electrical Overspeed Stops was performed on February 12, 1984. The surveillance readjusted the mechanical overspeed stops to less than 102.5%, thereby positively establishing the setpoints of the mechanical stops as required by the circular.

The inspector reviewed the completed surveillance procedure and surveillance authorization. No unacceptable conditions were identified. The review of the Unit 2 setpoint will be conducted during the startup test program.

2.10 <u>(Closed) Inspector Followup Item (387/84-07-02) Incorrect Revision of HPCI Diagram.</u>

During a system walkdown in March 1984, the inspector identified that the HPCI Process and Instrument Diagram (P&ID)(M-155) (uncontrolled) used for the walkdown was revision 20 whereas the controlled P&ID M-155 in the Stick Files was revision 19. The licensee investigated this problem and determined the following:

-- Revision 20 simply incorporated Design Change Notices (DCN) which were attached to the Stick File P&ID. Hence, there was no configuration difference between revision 20 and the revision in the Stick Files.

-- The cause of the problem was traced to August 1983 when PP&L Allentown was initially taking over drawing control from Bechtel. At that time, a distribution problem existed wherein some drawing mylars (used to develop the stick file drawings) were not sent to the site. The distribution problem was corrected in December 1983.

-- All drawings distributed during this period were reviewed against the Stick Files. Four drawings (including M-155) were found in the same configuration as M-155 (i.e. the stick File drawings had not been revised to incorporate attached DCNs). These drawings have been corrected.

The above actions resolved the inspector's concern,

2.11 <u>(Open) Construction Deficiency Report (388/83-00-14) Electrical Separation inside Multiple Division Pull/Junction Boxes.</u>

The deficiency reported by the licensee was improper electrical separation between multiple divisions of class 1E electrical cables and/or non-1E cables in pull/junction boxes. The licensee determined the primary cause of the problem to be the lack of clarity, understanding, and definition in the design documents. In addition the field construction forces installed unscheduled pull/junction boxes.

The licensee established a criteria for the type of separation barrier to be used where separation distances could not be maintained within pull/junction boxes. For circuits classified as high energy, a high energy barrier equivalent to two conduits spaced one inch apart would be installed. This barrier consists of a 1/2 inch marinite board sandwiched between two metal plates. The thickness of the plates is the same as the wall thickness of the box. For non-high energy circuits, or where voltage separation is required, a single metal barrier is installed with a thickness the same as the box wall thickness. All gaps of either barrier are to be filled with subliming thermolag 330-1 coating. The circuit classification of either high energy or non-high energy is contained in licensee letter PLA-2074 Attachment 2. Modifications were to be completed in accordance with Design Change Package 84-3049 dated 3/12/84. In addition to reviewing design documents, the licensee walked down Unit 2 to identify the separation discrepancies. The pull/junction boxes that required modification are identified in the associated non-conformance reports. The licensee will submit a final report in June 1984 to include all actions to prevent recurrence of this separation problem.

The inspector reviewed the associated documents and selected work authorizations for both safety and technical resolution. The inspector found the safety evaluation and the technical resolution satisfactory. The Quality Control Inspection Reports indicate that licensee QC personnel have a knowledge of the separation requirements and the modification procedure. This was evidenced by QC identification of some pull/junction boxes that required additional rework. The inspector randomly selected pull/junction boxes, JB-0044, JB-2152, Z-202 and Z-407 located above 4KV breaker 2A20301, for physical inspection. The barriers were installed in these boxes in accordance with the specified procedures. Although the licensee stated all the modifications have been completed, only NCR 84-231 has been closed at the time of this inspection. This construction deficiency is closed with respect to the installed modifications. However, the licensee's final report will be reviewed for recurrence prevention.

3.0 Review of Plant Operations

3.1 Operational Safety Verification

The inspector toured the control room area daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed. Status of control room annunciators were reviewed. Nuclear instrument panels and other reactor protective systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escorting, badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, control room, and field operator logs covering the entire inspection period. Sampling reviews were made of tagging requests, night orders, the jumper/bypass log, incident reports, and QA nonconformance reports. The inspector also observed several shift turnovers during the period.

3.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, penetration areas, reactor and turbine buildings, radwaste building, ESSW pumphouse, Circulating Water Pumphouse, Security Control Center, diesel generator building, plant perimeter and containment. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance, and availability of redundant equipment.

On April 17, during a tour of the Unit 1 reactor building, the inspector noticed that Containment Atmosphere Monitoring valve 157206, a local leak rate test (LLRT) manual one-inch valve, was closed but not locked closed. This is a containment isolation valve. The other valve in the test line, 157205, was locked closed and capped. Process and instrument diagram (P&ID) M-157 Revision 23 shows valve 157206 to be locked closed, as well as other LLRT test valves which are containment isolation valves. However, the checkoff list (COL) OP-73-001 indicates that 157206 should be closed but not locked closed. Similarly, other LLRT lines in the Containment Atmosphere Monitoring System which have two test valves and a cap were only required to have one valve locked closed and the other valve closed with the cap in place, per the COL. Examples of other LLRT valves which the P&ID indicates should be locked closed but are only required to be closed by the COL are 157203, 157197, and 157200.

Since these valves are LLRT test valves, they are not included in the containment isolation valve list in Technical Specifications and hence, the position of these valves is not checked on a frequent basis. The position of these valves would only be checked during performance of a system COL or after LLRT. System COL's are normally only performed on a refueling interval basis unless maintenance is conducted on the system. LLRT's are normally performed on a 24 month frequency. Since the positions of these valves are checked on an infrequent basis and they are containment isolation valves with no remote position indication, it is important that positive administrative controls govern their position. In addition, Administrative Directive AD-QA-302 Revision 1 "System Status and Equipment Control", Revision 1 dated June 20, 1983 Section 6.1.4.b.(2) specifies that manual containment isolation valves, including manual test valves for LLRT, required to be closed will be tagged and locked. Furthermore, P&ID M-157 indicates that these valves should be locked closed. Not locking closed valves 157206, 157203, 157197, and 157200 is a violation. (387/84-14-01)

The licensee is reviewing other system COL's to identify other systems where this problem may exist.

4.0 Licensee Event Reports

4.1 In Office Review of Licensee Event Reports

-- 82-012/01X-1. Potential for overload of the class 1E electrical system due to concurrent loading of Emergency Service Water pumps and either Residual Heat Removal or Core Spray pumps during a medium size LOCA.

-- 82-024/01X-1. Unanalyzed single failure that would cause a loss of cooling water flow to the Diesel Generators, resulting in their failure.

-- 83-140/03X-1. HPCI valve actuator's torque switch failed to actuate and caused motor damage.

-- 83-156/03X-1. Acoustical monitor VISH-14180A1 (for safety relief valve PSV-1F013B) failed on December 4, 1983.

**-- 84-001/01. H_2O_2 analyzer catalyst replacement.

**-- 84-003/01. Class 1E circuit isolators.

*-- 84-011/00. Unintential initiation of CREOASS and SBGT.

*-- 84-012/00. Off-gas hydrogen analyzers - missed surveillance.

**-- 84-013/00. Automatic scram on main turbine control valve fast closure.

-- 84-014/00. Transformer (T20) trip; CREOASS and SBGT initiation.

**-- 84-015/00. High background radiation surrounding service water radiation monitor.

-- 84-016/00. Missed channel check of new fuel vault criticality monitors.

*-- 84-017/00. Emergency service water spray networks frozen.

-- 84-020/00. RHR shutdown cooling isolation actuation.

* Further discussed in Section 4.2
** Previously discussed in Inspection Report 50-387/84-07; 50-388/84-08.

4.2 Onsite Followup of Licensee Event Reports

LER 84-017, Emergency Service Water Spray Networks Frozen.

The licensee reported on April 9, 1984 that two of the four spray pond riser networks were found to be frozen on March 10, 1984 during the performance of a weekly preventive maintenance activity which pumps down the risers. Outside air temperature was approximately 6°F when the frozen networks were identified. Unit 1 was shutdown throughout the event and Unit 2 was preparing to load fuel.

After four days of milder weather, all the networks were returned to service. The spray headers and risers were inspected and no damage was found. The networks were pumped down every two days and monitored for leakage every day until March 31, 1984, when the licensee considered that the probability of the risers freezing again would be very low.

A similar freezing event occurred on January 6, 1984 and was reported in LER 84-002. (See Combined Inspection Report 50-387/84-07 and 50-388/84-08). During the investigation performed in response to spray pond riser arm damage caused by ice formation on the spray nozzles in that event, the weekly preventive maintenance activity mentioned above was instituted to minimize the possibility of freezing in the risers.

The licensee has committed in the LER to install long term fixes by September 1, 1984 to ensure the freezing of the spray header does not occur again. The corrective action is required per a Unit 2 license condition, and will continue to be reviewed under Unresolved Items 387/83-29-03 and 388/83-32-02.

LER 84-011, Unintentional Initiation of Control Room Emergency Outside Air Supply System (CREOASS) and Standby Gas Treatment System (SGTS).

This LER documents two occurrences of actuation of CREOASS and SGTS, which are common systems to both Units 1 and 2, due to loss of a Unit 2 Reactor Protection System (RPS) bus during prelicensing work on Unit 2.

These occurrences are similar to those reported in LER 83-172 which was reviewed in Inspection 50-387/84-07; 50-388/84-08. As noted in that Inspection Report, the licensee intends to install constant voltage transformers on the RPS bus alternate power supplies which will prevent voltage degradations that cause loss of the RPS busses.

LER 84-012, Off-Gas Hydrogen Analyzers - Missed Surveillance.

This LER documents a missed surveillance on Off-Gas Hydrogen (H_2) Analyzer channel B on February 25, 1984. The missed surveillance, which was a monthly functional test, was detected 4 days later on February 29, 1984, during performance of the quarterly surveillance test. Hydrogen analyzer channel A was operable during this period and had recently (February 23) been calibrated. No increase in H_2 concentration was noted during this period and H_2 recombiner outlet temperature indicated that no abnormal H_2 concentration existed in the offgas stream.

The cause of the missed surveillance was personnel error. Instrument and Controls (I&C) personnel had elected to meet the requirement of the monthly functional test by performance of the quarterly calibration. However, the violation date for the monthly test, i.e. February 25, was not indicated on the quarterly Surveillance Authorization (SA) cover sheet. Therefore, the cognizant foreman was unaware of the violation date for the monthly test. The I&C surveillance schedulers have been counseled on this problem and have been directed to add a statement concerning the monthly functional test due date and violation date to the quarterly surveillance SA cover sheets, whenever quarterly tests are used to meet the monthly test requirements. Further corrective actions are planned and will be discussed in a supplemental report.

Missed surveillances have been a recurring problem for which the licensee instituted a major corrective action program. However, the circumstances associated with this missed surveillance would not have been prevented by the licensee's previous corrective actions. Therefore, this is a licensee identified violation which satisfies the tests set forth in 10 CFR 2 Appendix C Section V.A. Hence, the NRC will not issue a Notice of Violation for this occurrence.

5.0 Monthly Surveillance and Maintenance Observation

5.1 Surveillance Activities

The inspector observed the performance of surveillance tests to determine that: the surveillance test procedure conformed to technical specification requirements; administrative approvals and tagouts were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved surveillance procedure; test instrumentation was calibrated; limiting conditions for operations were met; test data was accurate and complete; removal and restoration of the affected components was properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and the surveillance was completed at the required frequency.

These observations included:

-- SO-150-002, RCIC Pump Monthly Quick Start and Flow Verification, performed on April 9, April 16 and May 4, 1984,

-- SO-152-002, HPCI Flow Verification, performed on April 19, 1984.

-- SO-159-010, Suppression Chamber Average Water Temperature Verification, performed on April 9, 1984.

On April 9, 1984 the inspector observed the performance of Unit 1 surveillance procedure SO-150-002, Revision 0, RCIC Pump Monthly Quick Start and Flow Verification, dated December 18, 1983. The test is performed to meet Technical Specification surveillance requirement 4.7.3.b and demonstrates that the RCIC system will quick start and pump at rated flow and rated pressure from the Condensate Storate Tank (CST) to the CST through the full flow test line. Although the Technical Specifications require the test to be performed quarterly, the licensee has increased the surveillance frequency due to repeated turbine overspeed trips during the last year.

On the test witnessed April 9, 1984 the RCIC turbine tripped approximately one second after it was initiated due to an apparent overspeed trip. The control room instruments indicated the turbine tripped but no alarm annunciators were received to verify the cause. All of the turbine trip functions alarm in the control room with the exception of turbine overspeed. A review of the computer generated data plots verified that none of the monitored parameters reached their trip setpoints. The turbine speed data was noisy and the computer channel had to be recalibrated. The Technical Specification Limiting Condition for Operation (LCO) was properly entered since the system failed the surveillance test.

During April 9-10, other tests were performed to investigate the problem. Four test runs were performed, and two quick starts failed due to overspeed trips. The turbine and system instruments and trip signals were checked during this troubleshooting and were verified to be set properly.

On April 11, the surveillance test was run successfully and the system was declared operable. The LCO was subsequently cleared. Due to the recent trips, the surveillance frequency was increased to five days initially and will be adjusted based on the results. The inspector witnessed successful tests performed on April 16 and May 4, 1984.

During the last year, three Licensee Event Reports (LERs) have been submitted describing similar trips. LER 83-051, dated April 21, 1983 described a RCIC overspeed trip following a low reactor vessel water level automatic initiation. The surveillance frequency was subsequently increased to monthly. LER 83-103, dated August 5, 1983 discussed a turbine overspeed trip during operability testing. LER 83-120, dated September 27, 1983, described another RCIC turbine overspeed trip following a scram. The licensee has determined that the turbine overspeed trips are caused by the slow response of the governor valve coupled with the rapid opening of the steam supply valve. The governor valve reacts too slowly to prevent an overspeed trip from a cold, standby condition. The governor valve standby position is full open, so on a system startup it must close to prevent an overspeed trip. It is hydraulically operated from an attached oil pump and the turbine must start rotating to build up oil pressure before the valve starts to close. All attempts to manually restart the system after an overspeed trip have been successful.

The licensee intends to adjust the surveillance test frequency based on test results and to determine the maximum periodicity to prevent test failures. The licensee is also evaluating modifications to adjust the steam supply valve opening time and to install a bypass around the steam supply valve, to allow for a slower startup ramp for the turbine. Based on the number of RCIC turbine overspeed events, it appears that installation of these modifications should be pursued on a priority basis.

This item will be reviewed in a subsequent inspection. (387/84-14-02)

5.2 Maintenance Activities

The inspector observed portions of selected maintenance activities to determine that: the work was conducted in accordance with approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and QC hold points were established where required; functional testing was performed prior to declaring the particular component operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

Activities observed included:

-- Repairs to Reactor Water Cleanup Outboard Isolation Valve (HV-244F104) performed on May 2, 1984. The valve failed a local leak rate test on April 30, 1984. The seat and disc were reworked. The valve passed the subsequent leak rate test.

-- Repairs to the RCIC injection valve (HV-249F013) performed on May 2, 1984. The valve failed a local leak rate test on April 30, 1984 and the disc and seat were reworked because of slight pitting on the stellite seating surfaces. The valve passed the subsequent leak rate test.

The maintenance activities observed were performed in accordance with the applicable requirements and found acceptable.

6.0 Summary of Operating Events

6.1 Unit 1

Unit 1 operated at full power throughout most of the report period. Several power reduction were performed in order to change demineralizer beds and to change rod patterns.

On April 17, 1984 the 'A' feedwater pump increased speed to its high speed stop. Reactor power was reduced to approximately 75% by lowering recirculation pump speed, and the feedpump turbine was tripped. Investigation revealed greasing problems in the feedpump turbine control linkage, which was corrected. The other feedpumps were inspected and found to be acceptable. After the repairs were completed, the Unit returned to full power operation.

6.2 Unit 2

Fuel loading operations, which started March 28, 1984 continued during the period and were completed April 13, 1984. The core verification was completed April 16, 1984 and no discrepancies were identified.

On April 10, 1984 core alterations were performed without an operable SRM in the associated quadrant, due to operator error, in violation of the Technical Specifications. (See Special Inspection Report 388/84-19).

After fuel loading operations were complete, the moisture separator, steam dryer, and vessel head were installed, and Operational Condition 4 was declared on April 19, 1984.

The operational hydrostatic test was performed from April 22 - 26, with only one valve failing the leak test. The Residual Heat Removal outboard injection valve (HV-251F015A) exceeded the Technical Specification leak rate of 1 gpm. The valve was disassembled and found to be seating improperly. Initial criticality had been scheduled for April 23, but the valve repairs caused about a 2 week delay. The valve was repaired and retested satisfactorily.

During the week of May 1, 1984 local leak rate tests were performed and several valves had to be repaired and retested. (See Detail 5.2) The valve repairs forced another delay in the initial criticality, which is now scheduled for May 8, 1984.

7.0 IE Bulletins

IE Bulletin 83-07, Apparently Fraudulent Products Sold by Ray Miller, Inc., was sent to the licensee for action on July 22, 1983. In addition, two supplements to the bulletin were sent providing additional information. The bulletin requested licensees to determine where suspect material had been installed, evaluate its safety significance, tag or dispose of the suspect material not yet installed, and provide a written report within eight months of the date of the bulletin.

The inspector reviewed the licensee's response, dated March 16, 1984 to ascertain whether the information submitted was technically adequate, satisfied the requirements established in the bulletin, and correctly represented the action taken by the licensee. The response included the information required and was within the time period stated in the bulletin.

After an extensive investigation, the licensee found that no Ray Miller, Inc. material was installed at Unit 1 or Unit 2. However, ultrasonic calibration blocks fabricated from Ray Miller material were supplied for use at the site by Nuclear Energy Services, Inc. The parts were procured from a different plant and time period than the materials described in the bulletin. Chemical and material examinations were performed on the material. Three discrepancies were identified as a result of the examination, but were determined to be acceptable from a materials standpoint for the intended use of the blocks, per the requirements of the applicable ASME codes.

The bulletin response was also reviewed by NRC Region I specialists and found to be acceptable. Based on the licensee's response and NRC review, the bulletin is closed.

8.0 Startup Test Program

8.1 Initial Fuel Loading

8.1.1 Documents Reviewed

-- Regulatory Guide 1.68, Revision 1, Initial Test Program for Water Cooled Nuclear Power Plants,

-- Final Safety Analysis Report,

-- Unit 2 Technical Specifications,

-- Startup Test Procedure, ST 3.0, Fuel Loading,

-- ST 3.1, Installation of Neutron Sources and Fuel Loading Chambers,

-- ST 3.3, Fuel Loading,

-- ST 3.4, Core Verification.

8.1.2 Inspector Witnessing

The inspectors witnessed portions of Unit 2 initial fuel loading during March 28 - April 16, 1984 to ascertain conformance to license and procedural requirements, observe the operating staff performance, and the adequacy of fuel loading records.

Inspector witnessing verified the following:

-- Constant direct communication was established and maintained between the control room and the refueling floor;

-- Nuclear instruments were properly calibrated and operating with a measurable count rate;

-- Minimum crew requirements defined by the procedures and Technical Specifications were met;

-- The proper revision of the procedure was utilized;

-- Inverse Multiplication plots were maintained in accordance with procedural requirements;

-- Proper controls were utilized for personnel access to the refueling floor;

-- Refueling status boards which mimic core and fuel pool locations were properly utilized and available on the refueling floor and the control room.

The entire core complement of fuel assemblies was prepared, inventoried and stored in the spent fuel pool prior to the start of fuel loading. The evolution was performed with the fuel pool and vessel cavity flooded to simulate refueling conditions and the fuel was loaded into the core from the center out in a roughly spiral pattern of increasing size.

Fuel Loading Chambers (FLC's) were initially utilized for neutron monitoring and were connected to the source range instrumentation. The Source Range Monitors (SRM's) were reconnected as their location was surrounded with fuel.

Fuel loading commenced on March 28, 1984, using the Fuel and Core Component Transfer Authorization Sheet (FACTAS) as the guiding document for the fueling stations. On March 29, after several bundles were loaded, a malfunctioning limit switch on the refueling hoist caused one fuel bundle to be dragged on the bottom of the refueling canal. The fuel end piece was the only part of the bundle which touched the canal floor. The limit switch was repaired and the fuel was inspected. No damage to the fuel was found, and fueling recommenced.

On March 31, the refueling hoist was damaged due to operator error and it was replaced with the Unit 1 hoist. Later, a malfunction in the reactor manual control system (RMCS) rendered the refueling bridge inoperable due to interlocks. Repairs to the RMCS were completed on April 2 and loading continued.

On April 5, a Reactor Protection System actuation was initiated by a spurious signal from Intermediate Range Monitor (IRM) channel 'D'. (All rods were already inserted). The IRM was not in the vicinity of fuel loading operations. The scram was able to be immediately reset. Investigation found a faulty voltage preamplifier which was replaced and tested satisfactorily. This was properly reported to the NRC in accordance with 10 CFR 50.72, and Licensee Event Report 84-001 was submitted on May 4, 1984.

On April 9, six consecutive scram signals occurred due to spikes on the IRMS. No scram signals sealed in. Fuel loading activities were halted and the shorting links temporarily installed to minimize the cycles on system components. The signals were apparently caused by electromagnetic interference. Functional tests were conducted on SRMS, IRMS and APRMS. No problems were found and the problem did not recur.

On April 10, the 'A' SRM was unable to be placed in service due to cable problems which were corrected. On April 11, the licensee discovered that the 'A' FLC/SRM had been bypassed during fuel loading operations in it's associated quadrant in violation of the Technical Specifications. (See Inspection Report 388/84-19). On April 11, all SRM's were declared operable.

On April 13, the last of the 764 fuel bundles was loaded in the core and the core verification was completed satisfactorily on April 16. The core verification was made after the conclusion of fuel loading to ensure the installation and configuration of core components was correct. No deficiencies were identified. The core shutdown margin was successfully demonstrated after 144 bundles had been loaded to verify that the partially loaded core was subcritical by at least 0.38% delta k/k with the analytically determined highest worth control rod fully withdrawn.

8.1.3 Findings

Through discussions with licensee personnel, review of documentation, witnessing of fuel movement during different shift periods and verification of nuclear instruments and recording of data, the inspectors verified that the acceptance criteria for the test procedures had been met. With the exception of the bypassed SRM during core alterations (discussed above), the evolution was conducted in a professional manner and in compliance with Technical Specifications.

9.0 TMI Action Plan Requirements

The inspector reviewed the licensee's implementation of commitments made in response to the following NUREG 0737 Requirements:

9.1 II.K.3.18 - Modification of Automatic Depressurization System Logic.

By letter dated October 1, 1982 (PLA-1312), the licensee adopted the results of the BWR Owners Group study on TMI Action Plan Item II.K. 3.18. To meet the action plan item, the licensee committed to modify the ADS logic to bypass the high drywell pressure trip after a sustained low reactor water level signal, and to add a manual switch that can be used to inhibit an automatic ADS actuation if required. The proposed bypass timer setting was 480 seconds. The proposal was reviewed by the NRR and found acceptable as documented in Safety Evaluation Report (NUREG-0776) Supplement No. 6.

In a letter dated February 22, 1984, the licensee requested that the completion date for plant emergency procedures and Technical Specifications related to the manual inhibit switch for the ADS be delayed for Unit 2 to be concurrent with the first refueling outage for Unit 1 because of potential complication in operator training. NRC review concluded that during the interim period, the manual inhibit switch should be disabled, and the use of the switch will be implemented at the same time for both units.

The inspector reviewed completed preoperational test P283.2A, Main Steam ADS/Safety Relief System to verify that the bypass timer and manual inhibit switch had been properly tested and met the acceptance criteria. Both were tested satisfactorily.

Unit 2 Technical Specification 3.3.3 was reviewed to verify that it correctly indicates the trip setpoint for the ADS Drywell Pressure Bypass Timer and requires the applicable surveillances. The Technical Specification requires the trip setpoint to be equal to or greater than 420 seconds. The associated work documents were reviewed, and verified that the four timers were calibrated to meet the Technical Specification requirement. The Safety Evaluation Report stated that a timer setting of less than 480 seconds was acceptable.

Design Change Package (DCP) KR2-989-0 installed the manual override switch in the Unit 2 ADS logic which could be utilized to override the ADS actuation logic to prevent an automatic ADS actuation if so desired. Plant Modification Record (PMR) 84-3054 disabled the override capability in Unit 2 by installing jumpers around normally closed contacts of the override switch and lifting leads from the normally open contacts. The inspector reviewed the PMR and work documents to verify the work was complete prior to Unit 2 initial criticality. No unacceptable conditions were identified.

10.0 <u>Exit Interview</u>

During the course of this inspection, meetings were held with plant management to discuss the inspection and findings.