U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-387/85-18; 50-388/85-16

Docket No. 50-387 (Cat C); 50-388 (Cat C)

License No. NPF-14; NPF-22

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: May 6, 1985 - June 23, 1985

Inspectors: Jack Strosnider for R. H. Jacobs, Senior Resident Inspector — 7/23/85 date

Jack Strosnider for L. R. Plisco, Resident Inspector — 7/23/85 date

Approved by: Jack Strosnider J. Strosnider, Chief, Reactor Projects Section IC, DRP — 7/23/85 date

Inspection Summary:

Areas Inspected: Routine resident inspection (U1 - 123 hours; U2 - 67 hours) of plant operations, licensee events, open items, surveillance, maintenance, Unit 1 refueling outage, allegation followup, and closeout of license conditions.

Results: Review of Unit 1 License Conditions found that the first refueling outage modifications were completed. (Detail 6.0); Review of over pressurization potential for Emergency Core Cooling Systems were adequate (Detail 7.0); Review of an allegation concerning drywell average air temperature found discrepancies in the associated procedures (Detail 8.0).

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Unresolved Item (387/85-13-01): Steam Dryer Failure Data

Inspector review of the licensee's letter from N. Curtis to W. Butler (NRR) dated May 14, 1985 and its enclosure 2 found that the list of outstanding information requested in paragraph 14.0 of inspection Report 50-387/85-13 has been satisfactorily resolved. The licensee response was complete and timely.

1.2 (Closed Construction Deficiency Report (387/82-00 06; 388/82-00-06; ESW Waterhammer During Shift to Emergency Diesel Generators

On May 5, 1982 the licensee reported, in accordance with 10 CFR 50.55(e), that during Unit 1 preoperational testing a waterhammer event had occurred in the ESW system which resulted in damage to three pipe hangers. A licensee investigation determined that under certain operational conditions the ESW system could be subjected to an unanalyzed waterhammer event. During a losss of offsite power (LOOP) when the ESW system was in operation, the ESW pumps would trip and the spray pond bypass valves would fail open, allowing the ESW piping at higher elevations to drain to the pond. After power restoration, via the diesel generators, the spray pond bypass valves would begin to close and the ESW pumps would restart (after a time delay). The pump restart would cause water to be discharged into the partially emptied ESW piping, resulting in a waterhammer. Licensee analysis found that the potential existed for the ESW system to experience stresses which could exceed the design allowables.

Temporary modifications to the ESW system were implemented, prior to exceeding 5 percent power on Unit 1, to reduce the waterhammer loads to an acceptable level until a permanent modification could be designed and installed. The modifications were required by Operating License NPF-14, Attachment 1, Item 3.a. The temporary modifications included installing motor operators on the pump discharge valves to throttle the initial flow of the pumps, adding a time delay to the opening circuit of the bypass valves, and staggering the starting times of the ESW pumps for more gradual filling of the system. These modifications and system testing were previously reviewed in Inspection Report 50-387/82-40.

In the licensee's final report concerning the CDR (PLA-1812) dated September 22, 1983, the licensee committed to install vacuum breakers during the first refueling outage for the long term corrective action and to demonstrate that all piping, hanger and anchor bolt loads are within code and NRC allowables either by analysis or testing.

The licensee issued Plant Modification Record (PMR) 83-592 for the first refueling outage to provide the permanent solution to the waterhammer problems. The basic theory of the modification was to prevent draindown of the ESW system during a LOOP by installation of additional check valves and isolation valves. When prevention of the draining could not be accomplished, vacuum breakers were installed to allow the voided piping to be filled with air to reduce the forces created when the piping refilled. The modification also removed the motor operators from the ESW pump discharge valves and shortened the time delay for the opening of the spray pond bypass valve to 30 seconds.

The inspector reviewed the PMR package and several of the associated Construction Work Orders (CWO). During the course of the outage the inspector witnessed the installation of several portions of the modification and reviewed the associated work documents. The work packages were complete and the work was conducted in accordance with the associated packages.

After completion of the modifications the inspector reviewed the Operational Readiness forms to verify that the required actions were completed prior to declaring the system operable. The inspector previously had several questions regarding the adequacy of post modification testing which resulted in an unresolved item. (See Special Inspection 50-387/85-16; 50-388/85-15).

Two portions of the modification were not completed during the outage. The change to the "A" loop low flow timer was not performed and the electrical connections to the new isolation valves on return line from the Unit 2 DX (direct expansion) units were not completed. The licensee stated that these portions were deferred until a later date. The NRC reviewed this change in the Safety Evaluation for Amendment No. 30 to NPF-14 (Amendment 6 to NPF-22) and found it acceptable until the modifications are completed.

PP&L analysis has shown that all piping, hanger and anchor bolt loadings during a waterhammer event are within NRC and code allowables with the current modifications installed. The commitments made concerning the ESW waterhammer modifications have been completed.

1.3 <u>(Closed) Inspector Followup Item (387/83-06-02): Reactor Mode Switch Failures</u>

On March 23, 1983 the licensee reported in LER 83-043 that the reactor mode switch did not initiate a full scram as designed when placed in the "Shutdown" position. The unit was in hot shutdown when this occurred. The licensee's initial corrective action was reviewed in Inspection Reports 50-387/83-06 and 50-387/83-12. These actions included contact verification following each mode switch change.

The licensee also reported a potential deficiency (10 CFR 50.55 (e)) concerning the Unit 2 Reactor Mode Switch on April 7, 1983, based on the Unit 1 switch failures.

The licensee performed several calculations and tests on various reactor mode switches and replaced the Unit 2 switch prior to fuel loading. NRC review of the switch testing and evaluation and Unit 2 switch replacement is documented in Inspection Report 50-387/84-07.

During the first refueling outage the Unit 1 reactor mode switch was replaced with a new dynamically qualified switch in accordance with modification PMR 85-3000. The inspector reviewed the completed Operational Readiness form which was performed on April 25, 1985.

1.4 (Closed) Weakness (388/83-19-04): Excessive Debris in the Unit 2 Reactor and Containment Buildings

During the special Construction Assessment Team inspection conducted in October 1983, the inspectors determined that plant cleanliness had not reached the level desirable for operational readiness and identified this as a weakness. It was noted that excessive debris in the form of trash, cigarettes and dirt was prevalent in the Unit 2 reactor and containment buildings.

Subsequent to the inspection, station personnel implemented a comprehensive post-construction cleanup effort to prepare the plant for operations. Followup NRC inspections since Unit 2 licenseing have found the plant housekeeping to be excellent, and the level of cleanliness has continued to be maintained due to management involvement.

1.5 (Closed) Violation (387/84-38-02): Compressed Gas Cylinders Stored in Unauthorized Location

On November 27, 1984 inspector found approximateluy 15 compressed gas cylinders stored in an unauthorized location, next to and physically tied to the safety-related outboard Main Steam Isolation Valve Leakeage Control System (MSIVLCS) piping on the 719 foot elevation of the Unit 1 Reactor Building.

The licensee immediately removed the cylinders from the safety-related area once it was identified. Storage racks for compressed gas bottles have been fabricated and installed in designated locations for the transient storage and/or staging of reserve bottles. Inspector tours subsequent to the finding have found that the storage racks are in use, and storage of cylinders is only in authorized locations.

The licensee has also included gas bottle storage as part of the daily plant walkdown and the monthly Duty Team's cleanliness inspection. Additionally, the superintendent of the plant issued a memo

to all plant personnel concerning the proper use and storage of compressed gas cylinders, and reinforcing the plant policy.

1.6 (Closed) Inspector Followup Item (387/84-22-03): Core Spray Valve Isolation Signal Not per Technical Specifications (LER 84-26)

License Event Report (LER) 84-026 documented that the isolation signals to the Core Spray Full Flow Test Valves were not as specified in Technical Specification 3.6.3-1 and FSAR Table 6.2-12. The Technical Specification and FSAR required the valves to isolate on low reactor vessel level or high drywell pressure. The as-built condition isolated the valves on low reactor vessel level or high drywell pressure with a low reactor pressure permissive signal. The immediate corrective actions were reviewed in Inspection Report 387/84-22.

Plant Modification PMR 84-3085 changed the isolation signal to the valves so that the reactor pressure permissive signal was deleted. The modification was completed during the Unit 1 first refueling outage. The inspector reviewed the Operational Readiness Form, which was completed April 26, 1985.

1.7 (Closed) Construction Deficiency Report (CDR) (387/81-00-33): Cavitation Caused by RHR Throtting Valve

In November 1981, the licensee identified a problem with cavitation and severe vibration in the RHR system caused by throttling the LPCI throttle valves (F017A and B) beyong their design range. This problem caused valve and pipe support damage. The problem in Unit 1 was reported in Licensee Event Reports (LERs) No. 83-034, 83-056 and 83-091 and was the subject of IE Information Notice No. 83-55. As interim corrective action, the licensee repaired the valves, replaced the valve discs and set administrative limits to maintain flow at about 10,000 gpm while in shutdown cooling. The existing valves were manufactured by Anchor Darling. The licensee committed to replace these valves with valves having better throttling characteristics during the Unit 1 first refueling outage.

PMR 82-051 installed new 20-inch throttling valves manufactured by Control Components, Inc. The new valves are non-conventional in that they use a disk stack consisting of many individual disks each having labyrinth flow passages. The position of the valve plug within the disk stack determines the flow by exposing more or fewer disk passages. The inspector reviewed the modification package, the Operation Readiness Form, RHR Operating Procedures OP-149-002 and OP-149-004, Emergency Procedure EO-100-009, and Technical Procedures TP-149-008, 009, 024 and 025. Because of the change in differential pressure characteristics between the old and new valves, new pressure reducing orifices were installed in the pump discharge lines. The inspector reviewed post modification testing of the valve instal-

lation which consisted of system flow tests while in shutdown cooling, vibration data, valve stroke timing, and hydrostatic tests. On the flow tests, the inspector noted that the throttle valves remained partially closed when full system flow was achieved. An Engineering Work Request was prepared to have NPE address this. The inspector discussed the test with NPE who indicated that they had reviewed NPSH calculations for the LPCI mode and correlated that data with the recent test results. They indicated that ample NPSH would be available in the LPCI mode. The inspector had no further concerns.

1.8 (Open) Unresolved Item (397/82-16-02): Correct ILRT Results for CRD Headers not vented and Safety Analysis of CRD Line Breaks

In May 1982 the inspector expressed a concern for the identified liquid leakage from the CRD system during a containment ILRT and stated that the matter should be evaluated and described fully in the ILRT Technical Summary Report. In a followup inspection performed in October 1982 (387/82-32), it was noted that the final ILRT report did not contain an evaluation of CRD line breaks for potential safety significance.

A subsequent licensee evaluation determined that since there was no reactor building isolation of the CRD hydraulic system charging water header, this could allow backflow from the containment through the HCU's to the turbine building. This was found to be a potential noncontrolled release of radioactive material during an accident scenario.

During the Unit 1 first refueling outage modification PMR 83-188 was completed which provided two check valves and the associated vent and drain valves in the reactor building to prevent system backflow to the turbine building.

This item will be further reviewed in Inspection Report 50-387/85-17.

2.0 Review of Plant Operations

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator, and nuclear plant operator logs covering the entire inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log and QA nonconformance reports. The inspector observed

several shift turnovers during the period.

On June 14, 1985 the inspector noted a Unit 2 valve out of its normal position. RCIC steam line drain outboard isolation valve (2F026) was closed, and it was required to be open. When questioned, the operators checked the operating procedure, which required it to be open, and reopened the valve. Review of the logs could not find any recent activity that would have required operation of the valve. The mispositioned valve did not affect the operability of the system.

On June 14, 1985 the inspector noted that the ESW system was aligned with the "A" loop supplying the division I diesel generators and the "B" loop supplying the division II diesel generators. This alignment appeared to be contrary to the operating procedure and the FSAR analysis, which states all of the diesels will be aligned to the "A" ESW loop. (See detail 6.1). The "A" loop logic includes an automatic transfer feature to the "B" loop on low flow, but the "B" loop does not have an automatic transfer feature. With two diesels aligned to the "B" ESW loop, single-failure of the "B" ESW loop bypass valve could lead to the failure of two diesel generators.

The inspector discussed the alignment with the Unit Supervisor and the responsible engineer. After review of the alignment, the division II diesels were realigned to the "A" ESW loop.

This item will receive further review in a future inspection (387/85-18-01).

2.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, cable spreading rooms, penetration areas, reactor and turbine buildings, security control center, diesel generator building, ESW pumphouse, 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 June 12, the inspector noted four 55 gallon drums of combustible material on the 779 foot elevation of the Unit 1 Reactor Building. Combustible Storage Request No. 519 was posted on the wall in the area, but the expiration date on the request was May 15, 1985. The request also required the drums of solvent to be grounded, but two drums were not grounded. The inspector discussed the deficiencies with the acting Fire Protection Engineer, and reviewed the Combustible Storage Log. It appears that several items utilized during the outage have expired requests and should be closed out. This is another example of recent problems found with the implementation of outage have expired requests and should be closed out. This is

another example of recent problems found with the implementation of the combustible control program and will be followed under open item 387/84-38-03.

3.0 Summary of Operating Events

3.1 Unit 1

Unit 1 continued with the first refueling outage which commenced on February 9, 1985. Fuel loading was completed on May 16 and the unit entered condition 4 on May 25. The reactor pressure vessel leak test was performed on May 27. The containment integrated leak rate test was completed on June 1, 1985.

Reactor startup commenced at 3:45 p.m. June 8 and reached criticality at 6:24 p.m. June 8. During the startup two valves were found open in the steam tunnel which should have been closed on the restoration of a LLRT. The valves were closed. Two manual scrams were performed on June 10 and 11 for rod scram timing and the Unit was returned to operation on June 12. The Unit reached 100 percent power on June 22.

3.2. Unit 2

On May 18, 1985 reactor power was reduced to approximately 18 percent and the main generator was taken out of service to allow repairs of a leaking main transformer nitrogen relief valve.

On May 30, 1985 at 4:00 p.m. unidentified leakage into the primary containment increased above the Technical Specification limit of 5 GPM. A shutdown was initiated at 6:15 p.m. after attempts to locate the leakage were unsuccessful. The reactor was manually scrammed at 2:34 a.m. May 31. Upon drywell entry, the "A" reactor recirculation pump discharge bypass valve (F032A) was identified as having a packing leak. The unit entered condition 4 at 4:10 p.m. After repairs to the valve, the unit returned to criticality at 1:05 a.m. on June 3.

4.0 Licensee Reports

4.1 In Office Review of Licensee Event Reports

The inspector reviewed LERs submitted to the NRC:RI office to verify that details of the event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1

*85-012-00, Four Fire Dampers Not Included in Surveillance Procedures

85-013-00, Loss of Alternate Sampling while SPINGS Inoperable

85-014-00, Inadvertent SGTS and CREOASS Start

85-015-00, Fire Wrap Not Installed

**85-016-00, Five Surveillances Completed Late

85-017-00, Unanticipated RWCU High Flow Isolation

***85-020-00, Three ESF Actuations Due to Shine from RPV

85-021-00, Three Diesel Generators Declared Inoperable

Unit 2

85-014-00, RCIC Inboard Steam Supply Valve Isolation

**85-015-00, "A" Loop ESW Exceeded LCO

*85-016-00, RHR System Waterhammer

*Previously discussed in Inspection Report No. 50-387/85-12; 50-388/85-12
**Previously discussed in Inspection Report No. 50-387/85-16; 50-388/85-15
***Further discussed in Detail 4.2

4.2 Onsite Following of Licensee Event Reports

For those LER's selected for onsite following (denoted by asterisks in Detail 4.1), the inspector verified the reporting requirements of 10 CFR 50.73 and Technical Specifications had been met, that appropriate corrective action had been taken, that the event was reviewed by licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits.

4.2.1 LER 85-020 (Unit 1), Standby Gas Treatment System (SGTS) and Control Room Emergency Outside Air Supply System (CREOASS) Actuations due to Reactor Vessel Shine

This LER describes three occurrences of Engineered Safeguards Feature (ESF) actuations on May 16 and May 19, 1985, when the SGTS and CREOASS actuated due to Reactor Vessel

and moisture separator shine.

On May 16, the "C" Residual Heat Removal pump was placed in service in the shutdown cooling mode. The system had been out of service for a long period during the refueling outage (which commenced February 9). The pump start resulted in dispersing crud throughout the reactor vessel and refueling cavity. The area radiation level at the reactor cavity railing increased initially to 30 mrem/Hr. The "shine" from the crud was sensed by the refuel floor high exhaust radiation detector which then actuated the associated ESF systems. The other actuations occurred during moisture separator movement and reactor cavity draining evolutions on May 19. All systems responded as designed during the actuations. There were no indications of airborne radiation.

This is the fourth LER in 1985 (see 85-01, 85-10, and 85-11) that describes automatic starts of the SGTS and CREOASS initiated by the refuel floor high exhaust radiation monitors. Although some corrective actions have been taken, the licensee is continuing to evaluate methods to prevent recurrence of these types of events.

4.3 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that the report included the required information; that test results and/or supporting information were consistent with design predictions and performance specifications; that planned corrective action was adequate for resolution of identified problems, and whether any information in the report should be classified as an abnormal occurrence.

The following periodic and special reports were reviewed:

-- Monthly Operating Report - April, 1985, dated May 7, 1985

-- Monthly Operating Report - May, 1985, dated June 10, 1985

-- Special Report - Non-Valid Diesel Failure, dated June 13, 1985

-- Special Report - RCIC/HPCI Injections, dated June 18, 1985

These reports were found acceptable.

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:

-- SE-024-A05, Eighteen Month Diesel Generator "A" 24 Hour Run and 4000KW Load Rejection, performed on May 17, 1985

-- SE-124-A02, Eighteen Month Diesel Generator "A" Auto Start and ESS Bus 1A Energization on Loss of Offsite Power, performed on May 17, 1985

-- SO-150-002, Quarterly Reactor Core Isolation Cooling Pump Flow Verification, performed on June 9, 1985

-- SO-152-002, Quarterly High Pressure Coolant Injection Flow Verification, performed on June 9, 1985

On June 9, with the reactor at 4% power, the inspector witnessed surveillance testing for the HPCI and RCIC systems. At 4:30 p.m. on June 9, reactor pressure reached 920 psig during the post refueling outage reactor startup. Technical Specifications require HPCI and RCIC to be tested with 12 hours of reaching operational pressure. At 8:45 p.m. the HPCI surveillance was performed and it failed to meet the acceptance criteria because it could not develop the required flow for the stated discharge pressure. HPCI was then declared inoperable. While corrective maintenance was being performed on the HPCI controller, RCIC was tested at 10:05 p.m. While RCIC was running, the operator stationed in the RCIC room noted lowering oil level and leaking oil from a strainer cover. The turbine was tripped at 10:15 p.m. and declared inoperable. With both HPCI and RCIC inoperable, the Unit entered Technical Specification (TS) 3.0.3 and the operators initiated actions in preparation for a plant shutdown.

At 11:25 p.m. HPCI was restarted, after adjustments were made to the flow controller. The surveillance was completed satisfactorily and

HPCI was declared operable at 1:00 a.m. June 10. After repairs were completed to the RCIC turbine it was successfully started at 2:10 a.m. and the LCO was cleared.

No unacceptable conditions were noted.

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:

-- Preventive Maintenance activities on the Emergency Service Water spray pond bypass valve and spray network header valve, performed on June 14, 1985.

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

6.0 Unit 1 License Conditions

The following items relate to specific license conditions (LC) as identified in Unit 1 Operating License NPF-14.

6.1 LC 2.C. (32): Emergency Service Water System

Prior to startup of Unit 1 following the first refueling outage, the licensee was required to complete design modifications to the Emergency Service Water (ESW) system, approved by the staff, to eliminate single failure in the ESW system which leads to the need for an uncooled Residual Heat Removal (RHR) pump.

On October 15, 1982, the licensee reported, in accordance with Technical Specification 6.9.1.8.h, the potential for an unanalyzed accident resulting from a single failure of a spray pond bypass valve (LER 82-024). Under normal plant alignment, all four Emergency Diesel Generators were cooled by the "A" ESW loop. Redundancy was provided by an automatic transfer to the "B" loop on failure of the

"A" loop pumps to start. Licensee review determined that if the "A" pumps did start, but the "A" loop spray pond bypass valve failed to open (single failure), cooling would be impaired to the diesel generators without capability for automatic transfer to the alternate cooling supply. The deficiency was not previously identified because the failure modes and effects analyses were performed based on the assumption that the bypass valves were normally open. As a result of waterhammer concerns (see Detail 1.2), the system configuration was changed to have normally closed auto-open bypass valves.

The interim resolution was to restrict plant operation to less than 25 percent rated thermal power and align the "A" and "C" diesel generators to the ESW "A" loop and the "B" and "D" diesel generators to the ESW "B" loop.

After a meeting with Region I and NRR on November 5, 1982, a low flow detector was installed in the ESW system which caused an automatic transfer to the "B" ESW loop if low flow was sensed in the "A" ESW loop. The installation and testing of this modification was reviewed in Inspection Report 50-387/82-40 and found acceptable.

The licensee found during their review that failure of a diesel generator ("A" or "B"), which powers the ESW spray pond bypass valve motor, would result in failure of the valve to open. In addition to the diesel cooling problem, this would also result in the loss of cooling water to both RHR pumps in the associated division, one core spray loop injection valve. If it is assumed that a break occurs in the recirculation discharge line that is supplied by the RHR pumps not affected by the loss of ESW, the remaining pumps would be ineffective because of injecting into the broken recirculation line. This scenario, which consists of a pipe break and a single failure, would result in only one core spray loop available for injection. Power and an intact flow path also would be available to one other LPCI pump, but component cooling water would not be provided. The licensee determined by testing that the RHR pump could operate for at least 10 minutes without cooling water, which was long enough to provide adequate core cooling per the FSAR ECCS analysis.

In a November 8, 1982 letter to the NRC, PLA-1388, the licensee committed to evaluate the system further and submit to the NRC by December, 1982, a final solution to the single failure problem such that reliance on a RHR pump without cooling would not be required. A license condition was added to Amendment No. 5 to the Operating License to complete the modification prior to startup after the first refueling outage.

By letter dated May 16, 1983, the licensee proposed a modification to repipe ESW cooling water to LPCI pumps "C" and "D" such that cooling water is provided by the opposite division ESW loop. Therefore, Division I ("A" loop) would provide cooling water to LPCI pumps "A"

and "D" and Division 2 ("B" loop) would supply cooling water to LPCI pumps "B" and "C". The NRC staff (NRR) reviewed the proposed modifications and concluded they were acceptable in a safety evaluation dated August 24, 1983.

During the Unit 1 refueling outage the licensee completed modification PMR 83-092 which repiped the ESW piping to the "C" and "D" RHR pumps. The inspector reviewed the modification package and the completed Operational Readiness Forms. The licensee reported in a letter dated June 10, 1985 (PLA-2484) that the design modifications to the ESW system, previously approved by the NRC staff, had been completed.

6.2 LC 2.C. (24): Containment Purge System

Prior to startup following the first refueling outage, the licensee was required to install design features (screens) on the containment purge system to prevent blocking of the purge and vent values by debris produced in an accident.

The inspector reviewed the Operational Readiness Form for Modification PMR-82-291 which installed the debris screens on the drywell purge supply and exhaust lines. The modification was completed on April 26, 1985. The licensee reported in a letter dated May 15, 1985 (PLA-2464) that the design feature had been installed and the license condition was completed.

6.3 LC 2.C (17) (b): Scram Discharge System Piping

Prior to startup following the first refueling outage the licensee was required to incorporate the following modifications into the scram discharge volume system:

(1) Redundant vent and drain valves, and

(2) Diverse and redundant SDV instrumentation for each instrumented volume, including both delta pressure sensors and float sensors.

The licensee reported in a letter dated May 20, 1985 (PLA-2470) that the design modifications on the scram discharge volume system had been implemented in accordance with License Condition 2.C(17)(b). The inspector reviewed the Operational Readiness Form, which verified completion of the modification, and modification package PMR 82-578, which described the modification. In addition, the inspector observed portions of the completed installation.

The modifications, as required by the license condition, have been completed.

6.4 LC 2.C.(16): Wetwell to Drywell Vacuum Breakers

Prior to startup following the first refueling outage, the licensee was required to implement design modifications on the wetwell/drywell vacuum breaker valves that included:

(a) installation of new disc assemblies, new shaft bearing caps; and

(b) replacement of the shaft, keys and turnbuckle with stronger materials.

The licensee reported in a letter dated May 22, 1985 (PLA-2465) that the design modifications on the wetwell/drywell vacuum breaker valves had been implemented in accordance with License Condition 2.C.(16). The inspector reviewed the Operational Readiness form, which verified completion of the modification, and the modification package PMR 82-810. The inspector also witnessed portions of the modification installation and observed the reinstalled vacuum breakers.

6.5 LC 2.C. (28) (e): Modification of Automatic Depressurization System Logic

Prior to startup following the first refueling outage, the licensee was required to implement the previously approved alternative logic modification of the Automatic Depressurization System (ADS).

The modification installed four timers which bypass the high drywell pressure portion of the ADS actuation logic after a specific time interval and added a manual switch which allows the operator to prevent an automatic ADS actuation. The bypass timer is actuated on low reactor water level (Level 1), and ADS is initiated when the timer runs out.

The inspector reviewed the Operational Readiness Form, completed on June 7, 1985 and the modification package PMR 82-523. The inspector also witnessed portions of modification installation. The Technical Specifications have been amended to include this logic circuit.

The inspector reviewed the emergency procedures to ensure that cautions exist concerning securing an ECCS system. The caution in EO-200-021 states that an ECCS system is not to be secured or placed in manual mode unless, by at least two independent indications; (1) misoperation in automatic is confirmed or (2) adequate core cooling is assured.

The Unit 2 manual inhibit switch, which had been jumpered pending completion of the Unit 1 modification, was made operable May 31, 1985 during a forced outage.

6.6 LC 2.C. (27): Emergency Diesel Engine Starting Systems

Prior to startup following the first refueling outage the licensee was required to install air dryers upstream of the diesel generator air receivers.

Modification package PMR 82-761 installed air dryers in each diesel generator bay. One aftercooler, air dryer assembly with pre-filter, desiccant air dryer and after-filter were installed in each of the compressor air-receiver trains (two per diesel). The addition of the air dryers is to provide long-term reliability of the air starting system by removing moisture from the compressed air. The licensee reported in a letter dated June 13, 1985 (PLA-2479) that the air dryers had been installed.

The inspector reviewed the Operational Readiness Form, completed June 7, 1985, and the modification package. Inspection of the modification installation and a comparison of as-built to isometric drawings was also performed with no discrepancies identified. The only portions of the modification which are safety-related are the Class IE power supply to the dryers and the piping interface with the air-starting system.

6.7 LC 2.C. (5): Qualification of Purge Valves

Prior to operating the containment purge and vent isolation valves greater than 2-in. diameter to permit opening by more than 50 degrees, the licensee was required to demonstrate that the valves were qualified to close from the full open position against peak LOCA pressure.

The NRC staff reviewed the licensee's submittals concerning operability of the containment purge and vent valves and determined the information demonstrated the qualification of the valve to close during a LOCA. This was documented in a NRC letter to the licensee dated July 26, 1983, and SER Supplement 6. The licensee committed in a letter dated April 13, 1983 to make the necessary modifications prior to startup following the first refueling outage. Only the 24 inch valves required modification.

The inspector reviewed the associated Operational Readiness Form, modification package PMR 83-189, and the Technical Specification change. The modification replaced the banjo assembly, bonnet and thrust bearings and removed the mechanical blocks.

6.8 LC 2.C. (23) (f): Seismic and Dynamic Qualification

Prior to startup following the first refueling outage, the licensee was required to fully qualify the Power Range Monitor Cabinet and the HPCI Turbine to the SORT criteria and provide the final qualification

reports to the NRC staff for review.

The licensee submitted in a letter dated June 5, 1985 (PLA-2478) the final qualification reports for the Power Range Cabinet and the HPCI turbine. Two modifications, PMR 82-374 and 84-3029, were performed during the first refueling outage to upgrade the HPCI turbine. PMR 82-374 added 17 supports to the HPCI skid to seismically qualify the HPCI turbine lube oil piping. PMR 84-3029 replaced unqualified instrumentation in the HPCI turbine lube oil and control system. The inspector reviewed the completed Operational Readiness Forms for the modifications. The qualification reports will be reviewed by NRR.

6.9 LC 2.E.: Exemption From Local Leak Rate Testing of RHR Relief Valve Penetrations

License Condition 2.E grants a one-time exemption to the requirements of 10 CFR 50 Appendix J for the performance of local leak rate testing (LLRT) of the RHR relief valve containment penetrations. Specifically, no provision existed to perform LLRT of the penetration following unbolting of flanges which is necessary to perform LLRT of the relief valves. Appendix J would require the performance of an Integrated Leak Rate Test (ILRT) since an LLRT could not be performed on this penetration. The exemption waived the requirements for the ILRT. The exemption is no longer in effect following the first refueling outage. During this outage, the licensee installed spectacle flanges in the 10-inch relief valve discharge lines as a means to permit LLRT of the penetration.

The inspector reviewed portions of modification PMR No. 82-399 which installed the spectacle flanges. Local leak rate testing (LLRT) of the affected penetrations and an ILRT of the containment were performed following the installation. Two 1-inch LLRT valves were installed upstream of each of the two spectacle flanges. Since there are no other valves between the LLRT valves and the containment penetration and there are no other isolation valves inside containment, the LLRT valves constitute containment isolation valves and, as such, are required to be locked closed per Administrative Procedure AD-QA-302, System Status and Control. The inspector noted that check-off lists for Unit 1 RHR, OP-149-001-2 and OP-149-001-5, did not list these valves. This was caused by an administrative error during the processing of a procedure change. The licensee issued a change to the procedure and verified that the valves were locked closed. The inspector examined the corresponding check-off lists in Unit 2 (the modification was previously installed on Unit 2) and noted that of the four corresponding valves, only two were indicated locked closed and none of the valves were indicated as containment isolation valves. The inspector checked the actual position of the Unit 2 valves and found them to be properly locked closed, however. Nevertheless, the check-off lists do not reflect the proper status of these valves (i.e. lock closed) and no containment tags were hung on

them. The Unit 2 valves are 251050, 251052, 251054 and 251055. The licensee agreed to review and correct the above discrepancies. These discrepancies will be reviewed in a subsequent inspection. (388/85-16-01) No other discrepancies with the modification were noted.

7.0. Overpressurization Potential for Emergency Core Cooling Systems

7.1 Introduction

At Region 1 direction, the inspector conducted a review of licensee's surveillance and maintenance programs affecting those valves which isolate primary coolant from low pressure ECCS piping and components. Past experience has identified a number of incidents at commercial reactors where surveillance and/or maintenance problems on these isolation valves resulted or could have resulted in overpressurization of associated low pressure ECCS systems. Specifically, IE Information Notice 84-74 dated September 28, 1984 describes three occurrences at BWRs where overpressurizations occurred or could have occurred due to improper maintenance on testable check valves. Two of the occurrences were due to maintenance actions on the air actuator and the pilot solenoid only; the check valve itself was not worked. The inspector review focused on this area. The review consisted of:

1) Identification and verification of the isolation interfaces between high and low pressure piping.

2) Evaluation of isolation valve surveillance and maintenance procedures.

3) Review of maintenance activities and practices that apply to the isolation valves, their actuators and associated controls.

4) Interview of selected licensee personnel involved in maintenance activities to determine their familiarity and knowledge of overpressurization concerns and industry experience.

7.2. Description of ECCS High/Low Pressure Interfaces at Susquehanna

LPCI Injection Lines - There are two 24-inch lines, each with a locked open manual valve, testable check valve, one normally closed (NC) motor operated valve (MOV) and one normally open (NO) MOV separating high and low pressure piping. The high pressure piping is 1500 psig design and low pressure is 450 psig. There is a 1-inch equalizing valve around the testable check valve. The testable check valve, equalizing valve, and the NC MOV (LPCI injection valve) have Technical Specification (TS) leakage limits of 1 gpm at 1000 psig. There is also a high/low interface pressure monitor with an alarm setpoint less than or equal to 400 psig. The LPCI injection and throttle

valves (the NO MOV) are interlocked such that only one of these valves can be open if pressure is greater than 430 psig.

-- RHR Head Spray - There is one 6-inch line with one check valve and two NC MOVs between the high and low pressure piping. The high pressure (reactor) is 1500 psig design and the low pressure if 450 psig design. The two NC MOVs have Technical Specification leakage limits of 1 gpm at 1000 psig. There is a high/low interface pressure monitor with an alarm setpoint less than or equal to 400 psig.

-- RHR Shutdown Cooling - There is one 20-inch line with two NC MOVs separating high and low pressure piping. The high pressure piping is designed for 1250 psig and the low pressure piping is designed for 125 psig. There is also a locked open manual valve inside containment. Both of the NC MOVs (F008 and F009) have closure signals on low RV water level, high flow or high area temperature. The valves are also interlocked to prevent opening above about 98 psig. The valves have Technical Specification leakage limits of 1 gpm at 1000 psig and there is a high/low interface pressure monitor with a setpoint less than or equal to 142 psig.

-- Core Spray - There are two 12-inch lines, each with a locked open manual valve (inside containment), a testable check valve, a NC MOV and a NO MOV separating the high and low pressure systems. The high pressure piping is designed for 1500 psig and the low pressure piping is designed for 475 psig. There is a one-inch equalizing valve around the testable check valve. The testable check valve, equalizing valve and the NC MOV (CS injection valve) have Technical Specification leakage limits of 1 gpm at 1000 psig. There is a high/low interface pressure monitor with an alarm setpoint of less than or equal to 460 psig. The CS injection and throttle valves (the NO MOV) are interlocked such that only one of the two valves can be opened if pressure is greater than 450 psig.

7.3. Surveillance Activities

The routine surveillance activities that apply to the RHR high/low pressure interface valves are described in the attached table (Attachment 1). In the "Summary of Test" column in this table, it is noted that for some tests, jumpers are used to continuously hold open testable check valves during leak tests or for other functions in the logic functional tests. In each case, the inspector verified that the procedure contains verification steps requiring a signature that the correct jumper was inserted and removed. The inspector also noted that the 1000 psig leak test procedure contained no precautions for potential overpressurization. This is further discussed in Attachment 1. No other surveillance concerns were identified.

On a sampling basis, the inspector also verified that 1000 psig leak testing was performed following maintenance on isolation valves which could affect the valve's leak tightness. No discrepancies were noted.

7.4 Maintenance Activities

To determine the extent and nature of maintenance activities on the pressure isolation valves in the RHR and Core Spray Systems, the inspector discussed this subject with a maintenance supervisor, maintenance planners and quality control personnel. In addition, the inspector reviewed the following documents:

-- Planned Maintenance Information System (PMIS) printout of all RHR and Core Spray completed maintenance actions from 1983 to present

-- Selected Work Authorizations (WAS) concerning maintenance on tested check valves

-- MI-PS-001, Revision 7, Maintenance Planners Guide

-- Vendor Manual IOM #79, concerning Atwood Morrill 24-inch testable check valve

The inspector noted the following during this review and discussion:

-- All maintenance action on the testable check valves, air actuators and pilot solenoid valves were designated as Q work.

-- There was active QC involvement when the check valves were disassembled. No QC involvement, other than review of the work package, was noted when work was limited to the air actuator. QC personnel indicated that they would increase their involvement in this area.

-- No specific procedure for working on the testable check valves exists. Instructions were included in the work plans and the applicable vendor manual was referenced. The maintenance supervisor committed to develop a specific procedure for these valves to include the air actuator.

-- Post maintenance testing following valve disassembly included valve stroking, LLRT and leak testing. Testing following work on the actuator was limited to valve stroking.

-- The maintenance planners guide, which includes recommended retesting following valve maintenance, properly designates that leak testing per Technical Specification 4.4.3 be performed following maintenance which could affect valve leak rate.

-- Most of the maintenance activities on the RHR testable check valves involved adjustment of limit switches. The pilot solenoid valves are included in an EQ PM program to be rebuilt every three years. No preventive maintenance is performed on the air actuator. There have been occasional failures of the bonnet to body pressure seal on the check valves.

-- The only maintenance noted on the Core Spray testable check valves involved limit switch problems, EQ PMs on solenoid valves and a pressure seal replacement prior to Unit 2 licensing.

-- There has been a history of problems on the Unit 2 LPCI injection valves, F015A/B, the normally closed pressure isolation valves. These valves are Anchor Darling motor operated gate valves installed horizontally. There have been several occurrences of excessive seat leakage caused by inadequate seating due to the horizontal installation. The Unit 2 valves were modified to add better wear materials in the body guides and disc guide slots in late 1984. Proper post maintenance testing was conducted following these repairs.

-- Maintenance planning personnel were only somewhat aware of industry experience with overpressurizing low pressure ECCS systems due to improper maintenance on these valves. They remembered discussing this subject with a maintenance supervisor previously.

-- Information Notice 84-74 was widely disseminated but the inspector did not identify any specific action taken as a result of the Notice.

7.5 Summary

In summary, inspector review of system design, surveillance and maintenance activities of high/low pressure interface devices did not reveal any major concern. Surveillances are comprehensive and leak checks are performed as required following valve maintenance. Jumper insertion and removal is verified. In general, post-maintenance testing following maintenance actions was adequate. The inspector noted that additional attention to maintenance on testable check valve air actuators and pilot solenoid valves is warranted. The licensee agreed to increase QC involvement and develop a specific maintenance procedure for the testable check valves and support components. The licensee also agreed to review their 1000 psig leak check procedures for the need for cautions for overpressurization potential. These actions will be reviewed in a subsequent inspection. (387/85-18-02)

8.0 Drywell Average Air Temperature Allegation

On April 15, 1985 NRC Region I received an anonymous allegation concerning the plants method of calculating Drywell Average Air Temperature. The inspector reviewed the temperature detector installation, Technical Specification requirements, surveillance procedures, and operating history to determine if the allegation could be substantiated.

8.1 Drywell Temperature Instrumentation

The primary containment drywell temperature monitoring system includes two redundant subsystems, with each having four dual element type resistance temperature detectors (RTD's) located throughout the drywell. The eight RTDs provide temperature indication on remote shutdown panel 1C201 and control room inner ring panel 1C601 and are recorded on control room back panel 1C693. Only two of the elements (TE-15790A and TE-15790B) are utilized for indication on panel 1C601, and all are utilized for recorder, computer, and alarm inputs. Temperature indicators on control room panel 1C601 have a range of 40 - 440 degrees F and the recorder on panel 1C693 has a range of 50 - 350 degrees F.

8.2 Technical Specification Requirements

Technical Specification Limiting Condition for Operation (LCO) 3.6.1.7 (both units) states that drywell average air temperature shall not exceed 135 degrees F while in Operational Condition 1, 2 and 3. The associated Surveillance Requirement, 4.6.1.7., states that the drywell average air temperature shall be the arithmetical average of the higher temperature at a minimum of three of the four elevations and shall be determined to be within the limit at least once per 24 hours.

Technical Specification LCO 3.3.7.5 requires that, while in Operation Conditions 1 and 2, two channels of drywell temperature accident monitoring instrumentation are to be operable. Surveillance Requirement 4.3.7.5 requires that a Monthly Channel Check and 18 Month Channel Calibration be performed to demonstrate operability.

The Technical Specification basis for maintaining Drywell average air temperature below 135 degrees F ensures that the containment peak air temperature does not exceed the design temperature of 340 degrees F during LOCA conditions since the safety analysis assumes the drywell temperature is less than 135 degrees F for initial conditions. The temperature monitoring system also serves to permit control of environmental conditions for instrumentation and is capable of detecting small leaks.

8.3 Surveillance Procedures

The inspector conducted an in-depth review of surveillance procedures associated with drywell temperature instruments to ascertain whether the surveillance of safety-related systems and components is being conducted in accordance with approved procedures as required by the Technical Specifications. The inspector also examined the technical content of the procedures to verify that the procedures correctly implement the Technical Specification Requirements.

8.3.1 Daily Average Temperature

Surveillance Procedure SO-100-007 (SO-200-007 for Unit 2), Daily Surveillance Operating Log, determines the drywell average air temperature at least once per 24 hours to meet Surveillance Requirement 4.6.1.7. The procedure requires all eight temperatures to be recorded from either the recorders on back panel 1C693 (TR-15190A, B) or the corresponding computer points. Next, the average of at least three of the four sets using the highest temperature of each pair is computed.

As further discussed in Detail 8.4, Unit 1 operators had routinely disregarded one reading in the past due to suspect indication, and only averaged the minimum of three. although non-conservative, this practice was acceptable by the Technical Specification, since only three are required.

The surveillance procedures currently does not take into account an asterisk in the Technical Specification surveillance requirement which states that measurements from the two lower elevations will only contribute one value towards the minimum three values required to compute the average. The procedure should be revised to include this restriction to prevent nonconservative and unacceptable calculations in the future.

The inspector reviewed the calibration records for the associated instruments to ensure they are properly and periodically checked since they are utilized to meet the surveillance requirement. All eight detectors, and their associated instrument loops (computer points, recorders) are included in the preventive maintenance program and calibrated on a periodic basis. Six instrument loops are calibrated on an 18 month frequency and two are calibrated on a 24 month frequency. The inspector verified that the instruments are currently calibrated. The accuracy for the recorders is plus/minus 6 degrees F (plus/minus 2%) as stated in FSAR Table 7.5-3. The allegation incorrectly stated that the accuracy is only 15 degrees.

8.3.2 Monthly Channel Check

Surveillance Procedure So-100-002 (SO-200-002 for Unit 2), Accident Monitoring Instrumentation Monthly Channel Check, performs the qualitative assessment of channel behavior during operation to meet Surveillance Requirement 4.3.7.5.

The inspector noted several problems with these procedures:

-- SO-100-002 requires that reading be recorded for instrument TR-15790A and TR-15790B. The procedure provides two blanks but the designated recorders utilize four pens each to provide indication for all eight detectors. The operator must choose a particular indication from the four. (As discussed in the following section only one of the four pens is calibrated by a surveillance procedure). The range of temperatures indicated may sometimes be as much as 20 degrees.

-- SO-200-002 was recently changed by PCAF 2-85-0111 to record readings for instruments TR-25790A1 and TR-25790B1 instead of TR-25790A and TR-25790B as was originally required. The PCAF was processed as a correction to typographical errors. These recorders are located on front panel 1C601 and provide only one indication each. Additionally, all of the recorder references in the procedures were not changed.

These procedures need to be clarified to ensure the proper instruments are being checked in the surveillance.

8.3.3 18 Month Channel Calibration

Surveillance Procedure SI-173-310 (SI-273-310 for Unit 2), 18 Month Calibration of the Drywell Temperature Channels TT-15791 A and B (Accident Monitoring), is designed to meet Surveillance Requirement 4.3.7.5. The inspector noted several problems with these procedures:

-- The Unit 2 surveillance procedure performs the loop calibration on a different instrument than the monthly channel check performance by Operations, although they should be performed on the same instrument.

-- The surveillance procedure performs the calibration on one pen of the four pen recorder, but the procedure does not delineate which pen is calibrated.

Currently the Unit 2 Monthly Channel Check and 18 Month Channel Calibration are performed on different instruments, but they should be the same. The inspector discussed the

discrepancy with operations personnel and I&C. The I&C section stated that the calibration procedures would be revised to perform the surveillance on the proper instrument. Additionally, the inspector discussed with NPE which instruments were the accident monitoring instruments. Although, I&C was surveilling the instruments on panel 1C693, the FSAR states that these instruments are not powered by a class IE bus.

8.4 Previous Equipment Problems

Startup Test series ST-32, Containment Atmosphere and Main Steam Tunnel Cooling, was performed on both units to verify the ability of the Drywell Coolers/Recirculation Fans to maintain design conditions in the drywell. Acceptance criteria for the test included:

-- The general drywell area is maintained at an average temperature less than or equal to 135 degrees F, with maximum local temperature not to exceed 150 degrees F.

-- The area beneath the reactor vessel in the CRD area is maintained at an average temperature less than or equal to 135 degrees F.

-- The area around the recirculation pump motors is maintained at an average temperature less than or equal to 128 degrees F, with maximum local temperature not to exceed 135 degrees F.

During the ST 32.2 test on Unit 1, the average temperature in the recirculation pump motor area was observed to be higher than the allowable 128 degrees F. Temperature element TE-15798A recorded temperatures as high as 140 degrees F. The maximum of 150 degrees F was not exceeded. Temporary instruments used during the test, located in other areas around the pumps, indicated acceptable temperature limits. On February 16, 1983 the location of the element was examined during a drywell entry and an infrared survey was conducted of the drywell. The survey found that the temperature element was located near uninsulated pipe hangers that had large heat losses. Additionally, the engineers found that the detector was located in an area where no air circulation was possible. Problems were also noted with the location of TE-15798B. Based on their findings, it was concluded that TE-15798A and B did not accurately represent drywell temperature. Operations was informed of the problem and decided to disregard the temperature indications during the performance of the average temperature surveillance. Until the modification was installed, Operations was requested to declare TE-15798A inoperable and annotate the surveillance cover sheet. This was transmitted to the Operations Staff on October 24, 1984, but was never implemented.

Based on the information gained from the survey, a request for modification (RFM) was prepared and approved. Plant Modification Record (PMR) 83-562 was completed during the Unit 1 first refueling outage and relocated the temperature elements. Also, a technical Specification change was submitted and approved which reflected the 'as-built' configuration of the plant (Amendment No. 34). The two detectors which were on elevation 711 feet in the recirculation pump area were relocated to elevation 737 feet to assure more appropriate monitoring of the temperature zones.

8.5 SPDS Algorithm

The Safety Parameter Display System (SPDS) algorithm previously averaged four temperatures chosen from the highest of each pair at the four elevations to calculate the drywell average temperature. The algorithm was then revised to throw out the highest of the four readings, and average the remaining three readings. The algorithm was altered because the SPDS was alarming due to the abnormally high reading element discussed in section 8.4. To clear the alarm, and prevent confusion for the operators who were receiving alarms when their hand calculated average was satisfactory, the algorithm was changed.

The algorithm obviously does not currently provide a conservative indication since the highest number is not used. Additionally, it does not delineate between the sensor in question and the others, it just throws out the highest number. Although this algorithm calculates the average non-conservatively for both units, it is not used for surveillance purposes.

Due to the nature of the SPDS system the Unit 2 algorithm was also changed, although they did not have the same equipment problem as Unit 1. The algorithm is now being returned to its original configuration following relocation of the Unit 1 temperature elements discussed in section 8.4.

8.6 Previous Significant Operating Occurrence Reports

On July 3, 1984 SOOR 1-84-378 was originated to discuss a finding identified by NQA which took exception to the method being utilized to determine the average drywell air temperature (dropping highest value). Their review of Unit 1 surveillances from May 27, 1984 to June 24, 1984 found twenty-two of the thirty surveillance used only three of the readings, and discarded the highest reading. In addition, the cover sheets for the surveillances had the "no" block checked for components/systems inoperability or criteria failure.

Licensee representatives discussed this practice with the Resident Inspector after the SOOR was originated. The inspector stated that the practice did not meet the intent of the Technical Specification,

unless there was a technical justification for not utilizing the value (as there was in this case), but it did meet the surveillance requirement as stated.

The Engineering staffs position was that if the number was not going to be utilized in the average, the associated detector should be declared inoperable. The Plant staff position was that the temperature indication was correct, but not indicative of the average air temperature.

8.7 Summary of Findings

-- The current SPDS algorithm calculates the average drywell temperature in a non-conservative fashion since Unit 2 does not have the same design deficiency Unit 1 had encountered. Although this does not meet the intent of the Technical Specification it is not utilized to meet the surveillance requirement. The algorithm is being returned to its original configuration.

-- Although one Unit 1 detector provided non-representative data, due to its location, since startup testing, the detector has been relocated by a modification and all four levels should be used in the future calculations.

-- Several surveillance procedures were found with some minor deficiencies that should be corrected to provide consistency, and to prevent inadvertently not meeting the Technical Specification requirements.

-- The plant should determine which of the eight drywell temperature detectors will be designated the Accident Monitoring channels and implement the required surveillances accordingly.

-- The preventive maintenance calibration frequencies of the eight temperature instruments should be consistent. Currently six are at 18 months and two are at 24 months. In addition, two are already covered by surveillance procedures.

-- Although the plant was technically justified to disregard one temperature reading and meet the Technical Specification limit, it should not perform the calculation in this non-conservative manner on a routine basis. If operations intends not to use a detector in the future due to technical problems it should document its intention clearly to prevent confusion.

The surveillance procedures deficiencies are considered unresolved pending NRC review of the licensee's corrective action. (387/85-18) -03)

In addition to the above, the inspector noted that the operators continue to have difficulties in evaluating the data displayed on temperature recorders TR-15790A and B. This item was previously discussed in Inspection Report 387/82-39 (Unresolved Item 82-39-03) and has not yet been resolved and may require further management attention.

9.0 Exit Meeting

On June 27, 1985 the inspector discussed the findings of this inspection with station management. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.

SURVEILLANCE ACTIVITIES

RHR

TEST TYPE	FREQUENCY	TEST CONDITION	ACCEPTANCE CRITERIA	REGULATORY REQUIREMENTS	SUMMARY OF TEST
A. Valve Exercising	Q	Cold Shutdown	Specific times for valves	ASME Sect. 11	Isolation valves are stroked and timed using remote position indication
B. Leak Testing	18 months +	Reactor at	< 1 gpm at	T.S. 4.4.3	During leak testing of injection valves, jumpers used to hold the testable check valve open (i.e. air continuously supplied). Jumpers are verified removed in the procedure. The throttle valves are closed during testing of the testable checks and injection valves to prevent overpressurization. During testing of shutdown cooling valves, interlock bypassed to allow opening these valves one at a time. Insertion and removal of jumpers is verified. However, no cautions in procedure for overpressurization concerns.
C. Logic Functional Test	18 months	Cold Shutdown		T. S. 4.5.1	Check low pressure permissive for injection valves, high pressure interlock for SDC valves, etc. Many jumpers, lifted leads open links used. Independent verification of insertion and removal required.
D. LLRT Testing	18 Months	Generally performed in cold shutdown	Total for containment isolation valves <3.3 gpm at 49.5 psig	T.S. 4.6.1.2	Local leak rate testing