U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-387/84-18;
50-388/84-22

Docket Nos. 50-387 (CAT C);
50-388 (CAT B2)

License Nos. 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 8 - June 8, 1984

Inspectors:	Ebe McCabe, for R. Jacobs, Senior Resident Inspector	6/28/1984 date
	Ebe McCabe, for L. Plisco, Resident Inspector	6/28/1984 date
	for Jacque Durr R. Manoly, Reactor Engineer	6/27/84 date
	Gene Kelly G. Kelly, Project Engineer	June 26, 1984 date
Approved by:	Ebe McCabe Ebe C. McCabe, Chief Reactor Projects Section 1C, DPRP	6/28/84 date

Inspection Summary:

Routine resident inspection (U-1, 67 hrs.; U-2, 154 hrs.) of plant operations, equipment readiness, maintenance, surveillances, licensee events, startup testing, and IE Bulletins.

Inspector witnessing of Unit 2 initial criticality and startup tests conducted to date identified no unacceptable conditions (Detail 7.0). Reactor coolant system leak rate calculations meet NRC requirements (Detail 4.3).

Two violations were identified: the RCIC flow controller on Unit 2 was not returned to automatic following surveillance (Detail 2.1); and secondary containment integrity was not maintained on Unit 1 for 2 days (Detail 3.2).

An indicated above limit plant heatup rate was actually within limits but was missed by the operators and reviewing supervisors (Detail 10).

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DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Open) Unresolved Item (387/83-25-02; 388/83-24-01)

The inspector reviewed the licensee's transmittal of March 30, 1984 (PLA-2150) which includes the reanalysis of the drywell spray header piping.

The latest reanalysis was performed for containment spray header "A" (Line No. GBB-118) to address the concerns expressed by the inspector in Inspection Report 387/84-08; 388/84-09. The specific concerns related to the assumption employed in the previous piping analysis with regard to the free radial growth at the support locations due to thermal loads. The assumption was not justified since the piping thermal radial growth was limited by the amount of gap available between the piping and the supports.

The reanalysis considered the actual gaps in supports number GBB-118-H3, GBB-118-H4, GBB-118-H5, and GBB-118-H6. Although the maximum stress in the piping had increased by approximately 23%, it remained below code allowable limits. However, the weld stresses between the process pipe and the trunnions on supports GBB-118-H5 and GBB-118-H6 exceed the allowable limit of 15 ksi. Therefore, further justification is required for the acceptance of header "A" supports GBB-118-H5 and GBB-118-H6.

The revised analysis should be performed as a controlled design calculation and meet quality assurance requirements. Additionally no justification was provided for the acceptance of the piping and supports for header "B", Unit 1, Line No. GBB-118; and headers "A" and "B" of Unit 2, Line No. GBB-218.

This item remains open pending the resolution of the above issues.

1.2 (Closed) Construction Deficiency Report (388/83-00-03) Feedwater Bypass Leakage

In a letter dated May 4, 1984 (PLA-2192) the licensee submitted proposed amendments for the Unit 1 and Unit 2 Technical Specifications to reflect bypass leakage limits on the feedwater lines and to require pneumatic local leak rate tests. This completes the action required by Item 2a of Attachment 1 to the Unit 2 operating license.

This item was previously reviewed in Inspection Report 50-387/84-07; 50-388/84-08 dated May 1, 1984.

1.3 (Closed) Construction Deficiency Report (388/84-00-03) Base Metal Cracking in Angle Fittings Used on Class 1E Electrical Raceways and HVAC Supports

The licensee's final report on the deficiency involving base metal cracking and bending of angle fittings used on Class 1E electrical raceways and Category 1 HVAC supports was submitted to the NRC on June 1, 1984 (PLA-2215).

Based on testing and evaluation, the licensee determined that the deficiency is not reportable under 10 CFR 50.55(e) since the fittings are capable of supporting the loads imposed upon them during normal and faulted conditions. A testing program was performed to prove that the fitting load carrying capability was acceptable, and field walkdowns were conducted to determine the actual loads on the supports and compare these loads to the test results. All connection loads were determined to be less than the allowables. The final report and test results were reviewed and found acceptable.

This item was previously reviewed in Combined Inspection Report 50-387/84-07; 50-388/84-08.

2.0 Review of Plant Operations

2.1 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, plant control operator, and nuclear plant 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.

At 9:15 a.m. on May 17, while conducting a walkdown of the Unit 2 control room panels, the inspector noted that the RCIC flow controller was in manual instead of automatic as required. After questioning the control room operators, it was determined that surveillance test SO-250-003, Revision 0, 18 Month RCIC System and Logic

Functional Check had been completed at 5:40 a.m. and the system was declared operable at 6:44 a.m. Although preparations were being made to increase plant pressure, reactor pressure was approximately 140 psig, and Technical Specifications do not require the system to be operable until plant pressure is greater than 150 psig. In step 6.13.16 of the procedure, RCIC System Restoration, the operator is to ensure the RCIC system is aligned for automatic operation with the RCIC pump flow controller in automatic and set for 600 GPM. Apparently, the operator performing the test did not properly complete the system restoration. In addition, from the time the surveillance was completed at 5:40 a.m. until the inspector discovered the mispositioned controller at 9:15 a.m., several control room panel walkdowns were conducted and the discrepancy was not identified.

The pressure recorders for this time period were reviewed and reactor pressure did not exceed 150 psig, therefore the Technical Specification was not violated. The failure to properly perform the surveillance procedure and return the system to its automatic start alignment is a violation of Technical Specification 6.8. (388/84-22-01)

The inspector also noted that the step requiring the controller restoration was not a step requiring an entry to be recorded on the attached Data Form. Similar procedures for other systems, (i.e. HPCI) and other RCIC surveillances were reviewed and they required this step to be recorded, and required a verification.

Upon identification of the mispositioned controller, the control room operator returned the system to the automatic lineup, made a log entry, and issued a Significant Operating Occurrence Report.

2.2 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.

While the licensee was making preparations for initial criticality, the inspector made a number of tours of the Unit 2 drywell to observe cleanup. On May 4, the inspector conducted a more indepth inspection of the drywell and verified the following: all downcomer covers were bolted in the "up" position; the CRD housing support was in place; foreign materials were removed (or included on a list to be removed); and there were no loose or disconnected wires underneath the vessel. A few minor discrepancies were found and were corrected prior to containment closeout.

3.0 Licensee Reports

3.1 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 the 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

*-- 84-018/00 Reactor Recirculation Pump Discharge Valve Stem Galling.

-- 84-019/00 Inadvertent Engineered Safety Features Actuation.

-- 84-021/00 Raceway Fire Barriers Not Installed.

-- 84-022/00 Spurious Actuation of Turbine Building SPING Flush.

-- 84-023/00 High Sodium Pentaborate Concentration.

*-- 84-024/00 Reactor Building Ventilation Zone Cross-connected.

-- 84-025/00 Two Main Turbine Surveillances Completed Late. (will receive further review in the next inspection report)

Unit 2

***-- 84-001/00 RPS Actuation on Spurious IRM Signal.

+-- 84-002/00 Core Alterations Performed with SRM Channel 'A' Inoperable.

***-- 84-003/00 Multiple RPS Actuation.

**-- 84-004/00 Unplanned ESF Actuations.

* Previously discussed in Combined Inspection Report 50-387/84-07; 50-388/84-08

** Further discussed in Section 3.2.

*** Previously discussed in Combined Inspection Report 50-387/84-14; 50-388/84-16.

+ Previously discussed in Special Inspection Report 50-388/84-19.

3.2 Onsite Followup of LERs

3.2.1 LER 84-024, Unit 1 Reactor Building Ventilation Zone Cross-connected

This LER documents an unintentional cross-connection of ventilation Zones II (Unit 2 Reactor Building) and III (Refueling Floor) on April 22, 1984, while Unit 1 was in Operational Condition 1 (Power Operation) and Unit 2 was in Operational Condition 5 (Refuel). This condition existed for two days (April 20 - 22).

Zones II and III were cross-connected via four hatches which provide ventilation to the area under the drywell head, and via the drywell personnel access hatch (both airlock doors were open to the Unit 2 Reactor Building). The Unit 2 drywell head was not in place and the reactor cavity had been drained. Hence, a ventilation flow path existed between the common refuel floor and Unit 2 drywell to the Unit 2 Reactor Building. Although not required in Operational Condition 5, secondary containment was maintained in Unit 2 including the required 1/4 inch vacuum in Zone II, preventing a direct flow path to the environment. However, since the zones were cross-connected, secondary containment integrity per T.S. 3.6.5.1 and 1.37 was not maintained, and a potential flow path to the environment existed via the Unit 2 ventilation system and the cross-connection. When this condition was discovered at 5:00 a.m. on April 22, the T.S. LCO was entered, and the condition corrected within 25 minutes by shutting one of the personnel airlock doors.

The inspector reviewed General Operating Procedures GO-100-006 and GO-200-006, Refueling to Cold Shutdown, Units 1 and 2 respectively, which contained cautions about ensuring drywell and equipment access hatches are shut prior to opening ventilation (reactor cavity) hatches with the drywell head not in place. These cautions were in place prior to this event. Maintenance Procedures MT-162-010 and MT-262-010 for reactor vessel insulation installation, were revised after this event to ensure that the personnel access hatch interlocks are in effect prior to opening reactor cavity penetrations. Other maintenance procedures, for drywell head removal and vessel insulation removal, highlight notifying Operations when opening the ventilation hatches.

However, these corrective actions do not address the central cause of this event, that of equipment control. The Work Authorization, U43206, for opening drywell head area hatches was authorized February 4, 1984, long before this event occurred. Additionally, no specific Equipment Release Form (ERF) or other specific operations authorization was required immediately prior to conducting this work. ERF A23099, which requested blocking of drywell coolers in order to perform this work, was issued by Operations but the ERF did not specifically authorize opening drywell head area hatches.

Therefore, Operations, which is responsible for maintaining Secondary Containment Integrity and compliance with T.S., had no specific control over this work. Additionally, the changes to the maintenance procedures are not sufficient to prevent recurrence since they address only the personnel access hatches and not other drywell-to-reactor building penetrations such as the CRD removal and equipment hatches.

Although the licensee identified and reported this occurrence, the corrective action taken was found to be insufficient to prevent recurrence. This occurrence is a violation of T.S. 3.6.5.1. (387/84-18-01)

3.2.2 <u>LER 84-004, Unplanned Engineered Safety Features Actuation</u>

This LER documents an unplanned Division II, primary containment isolation signal on Unit 2 caused by an unintentional grounding of a Visicorder during test setup on May 1, 1984 at 7:55 a.m. Unit 2 was in cold shutdown with unirradiated fuel (prior to initial criticality) at the time.

The Division II isolation signal caused a Standby Gas Treatment System initiation, Control Room Emergency Outside Air Supply System (CREOASS) initiation, and isolation of shutdown cooling. All systems functioned properly on the isolation signal. The signal was caused by a fuse which blew when one lead of a visicorder touched the metal floor while the other lead was connected to the positive side of the isolation circuit. The I&C technician recognized the problem and reported it to the control room. The fuse was replaced and the isolation signal was reset at 8:15 a.m. and all systems recovered by 8:40 a.m.

The inspector discussed the event with the I&C Supervisor. Test equipment groundings causing actuation signals have been rare. Terminals used for frequent lead hookups are being modified where possible to provide better hookup capability. This occurrence involved infrequent testing during troubleshooting. The event has been reviewed with I&C personnel. The inspector had no further questions.

3.3 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 1984

-- Special Report - Unit 2 Zone II Ventilation, dated May 23, 1984.

The above reports were found acceptable.

3.4 Part 21 Report - Crosby IMF-2 Pilot Solenoids

The licensee submitted a Part 21 report to Region I by letter dated April 9, 1984, describing an unusual incidence of shorts-to-ground experienced on Crosby type IMF-2 solenoids used on all main steam line safety/relief valves (SRV's) for both units. The report described a total of 10 failures, which represented over 10% of the solenoids tested at Susquehanna. All currently installed solenoids have been successfully tested (high voltage "megger" resistance check) in accordance with General Electric FDDR recommendation, and existing continuity and ground fault detection circuitry is available to detect future potential shorts which may develop.

GE and Crosby were contacted by a Region I inspector to determine the details and extent of this problem. The failures observed at Susquehanna were similar to those experienced at the LaSalle and WNP-2 plants, the latter experiencing a 22% failure rate. GE tests at San Jose on the failed components identified a localized manufacturing defect (stress area in the coil windings where insulation breakdown and electrical arcing was evident) which, in some but not all test cases, prevented energization of the solenoid when 125 VDC was applied. This condition raises questions concerning the adequacy of the electrical instulation between the solenoid's magnet wire and spool flange. The mechanical SRV function is unaffected by this problem.

GE and Crosby are jointly working upon an improved solenoid design, most probably similar to the solenoids used at the River Bend site which employ double windings and higher stress insulation for upgraded environmental qualification to NUREG-0588 requirements. However, it is their position at this time that the IMF-2 solenoids which have experienced the shorts, as detected by the high voltage resistance tests, represent an "infant mortality" problem which has been identified and corrected. In a June 15, 1984 GE letter to NRC, an interim report was presented which established justification bases for continued plant operation. GE engineering evaluation is not yet complete as to reportability under 10 CFR Part 21, and is being followed by NRC Headquarters.

4.0 Monthly Surveillance and Maintenance Observation

4.1 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-252-003, 18 Month HPCI System and Logic Functional Test, performed on May 16, 1984.

-- SO-150-002, RCIC Pump Monthly Quick Start and Flow Verification, performed on June 4, 1984.

On May 16, 1984, the inspector observed performance of Unit 2 surveillance procedure SO-252-003, Revision 0, 18 Month HPCI System and Logic Functional Test, dated November 14, 1983. The test was performed to verify that the HPCI system would properly respond to an initiation signal and carry out the design features of the system. The test was being conducted for the first time on Unit 2 and was required in order to declare HPCI operable prior to continuing the heatup testing phase. The test had been attempted on May 14, 1984 but was unsuccessful due to instrumentation deficiencies, a leaking pump discharge check valve, and an incorrectly sized test-line flow orifice. These items were subsequently corrected.

On the test witnessed May 16, 1984, the HPCI turbine automatically started on three separate initiations, but the flow controller was not set properly causing the flow rate to be outside the acceptance criteria (greater than 5,000 gpm). Indicated flow was approximately 4,850 gpm with the controller set at 5,000 gpm. The controller was adjusted several times during the testing, but the problem was not corrected. Another difficulty was control room turbine control valve indication which was not operating correctly. A work authorization was issued and the valve movement was monitored visually thoughout the remainder of the test. The test was run successfully on May 17, after the repairs were completed on the flow controller and control valve indication, and the system was declared operable.

Several deficiencies were noted in the review of the procedure:

-- The procedure required the operator to verify that the "white" HPCI initiation indicating light was on after the auto-start. The light was actually "red" on the panel. The initiation lights on the RHR and Core Spray were green, and the RCIC light was also red. All of the initiation lights on Unit 1 are white. The procedure needs to be revised to reflect as-built conditions and the licensee needs to evaluate the apparent human factors deficiency.

-- One test acceptance criteria appeared to be ambiguous. It required that pump discharge pressure be "greater than or equal to" 210 plus/minus 15 psig. The actual pressure observed was approxi-mately 220 psig, and was within the Technical Specification limits of 210 plus/minus 15 psig. The procedure needs to be revised to clarify the acceptance criteria.

-- The procedure had four procedure change approval forms (PCAF) attached with the oldest approved change dated November 19, 1983. Administrative Procedure AD-QA-000, Revision 0, Procedure Changes, dated September 15, 1983 states that a procedure should normally be revised within sixty days from the approval date on the oldest PCAF or when three approved changes have accumulated against any particular procedure.

The inspector discussed this item with the responsible licensee personnel, who stated that the procedure will be revised once the changes noted in the running of the test are documented, since this was the first time the procedure had actually been utilized. The inspector reviewed the tracking system used for the PCAF's and determined that they were effectively controlled.

These procedure deficiencies will be reviewed in a subsequent inspection. (388/84-22-02).

4.2 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 Unit 2 "B" Loop LPCI Injection Valve (2F015B) performed during May 28 - June 6, 1984.

--Repairs to Unit 2 Turbine Bypass Valve No. 1 performed during May 28 - June 7, 1984.

4.2.1 LPCI Injection Valve Leakage

On May 21, while performing preventive maintenance on the "B" loop LPCI testable check valve and testable check bypass valve, both valves provided dual indication (open and closed) after cycling.

During subsequent troubleshooting, the pressure indicator for the associated RHR heat exchanger was found to be approximately 250 psig higher than the normal pressure. Investigation determined that the LPCI injection valve 2F015B was leaking. The 2F015B valve was then closed and deenergized. In addition, the upstream manual isolation valve, 2F017B, was also closed to meet primary containment integrity requirements. Further testing was then conducted, and it was determined that the 2F015B valve was leaking at a rate of 2.5 gpm, in excess of the Technical Specification limit of 1 gpm. To meet the Technical Specification action statement, the 2F017B valve was shut and deactivated in order to isolate the high pressure portion of the affected system from the low pressure portion. Also since the LPCI loop was declared inoperable on May 21, Technical Specifications required plant shutdown in seven days if the loop was not restored.

On May 28, 1984, Unit 2 shutdown and repairs on the valve commenced. The valve was disassembled and it was determined that the disc guide had to be repaired to ensure proper seating. The valve is installed horizontally and the upper disc face was not seating properly because the disc bottom guide provided too much clearance. The bottom guide was built up with weld metal and the valve reassembled. The valve passed subsequent leak rate testing on June 6, 1984, and the inspector had no further questions on this item.

4.2.2 Turbine Bypass Valve Repairs

On May 28, 1984, the #1 Turbine Bypass Valve (BPV) on Unit 2 was determined to be not fully closing. After Unit 2 shutdown, mechanical maintenance verified, by disconnecting the actuator from the valve, that the binding was in the seat/disc area of the valve. Upon valve disassembly, a welder's chipping hammer was found lodged between the seat and disc of the valve. The hammer had a head approximately 6 inches long with approximately six inches of handle intact. The metal spring handle portion of the hammer was apparently severed by bypass valve operation and is lost in the downstream piping or the main condenser.

Since the spring portion of the hammer (estimated to be about four inches long and one-two inches wide) was not retrieved, the inspector discussed with the licensee the safety significance of having loose parts in the steam or condensate system. Loose parts in the steam or condensate system would not pose a safety concern unless they could get into the reactor vessel. All condensate flow goes through the condensate demineralizers, which would trap any object upstream of the demineralizer.

The inspector also discussed with the licensee why the preoperational test program didn't previously discover the hammer. Between May 21 - 24, 1983, the licensee conducted an integrated flush of the reactor coolant and connecting systems. The inspector examined the completed test procedure for the flush, TP 5.26. The feedwater portion of the flush was performed by running the condensate pumps with the feedwater pump internals removed, and injecting into the vessel. The feedwater sprayers were also not in place. The steam lines were flushed by gravity draining from the reactor cavity through the steam lines to the condenser. The steam lines were flushed one at a time with the turbine bypass valve internals removed. The flushes of the steam lines lasted between six hours and 40 hours for the shortest and longest flush of the steam lines, respectively. The flushes continued until samples taken at various points (with flush cloths and chemical analyses) indicated that the system met cleanliness requirements. Apparently, the flush flow rates and pressure from the gravity flush were insufficient to remove an object such as a hammer.

After the reactor coolant system flush, the vessel was inspected prior to installing the vessel internals. On July 17, 1983, as a result of a dropped tool, the vessel was inspected and debris was found in some of the control rod guide tubes. This lead to another vessel inspection involving pulling every control rod out of its guide tube and checking for debris. Additionally, prior to fuel load, another vessel inspection was performed.

Repairs to the BPV consisted of reworking the seat which had been dented and replacing the disc. The valve was satisfactorily tested at pressure on June 13, 1984.

The maintenance activities observed were performed in accordance with the applicable requirements and found acceptable. The inspector had no further questions on this matter.

4.3 Review of Reactor Coolant Pressure Boundary Leakage Detection

Reactor Coolant Pressure Boundary leakage surveillance was reviewed for conformance to the Technical Specifications of Regulatory Guide 1.45, and FSAR commitments.

The following documents were reviewed:

-- Technical Specifications 3.4.3.1 and 3.4.3.2,

-- FSAR Sections 5.2.5 and 9.3,

-- Surveillance Procedure SO-100-006, Revision 2, Shiftly Surveillance Operating Log, dated May 7, 1984,

-- SO-100-007, Revision 2, Daily Surveillance Operating Log, dated April 30, 1984,

-- SO-200-006, Revision 3, Shiftly Surveillance Operating Log, dated June 5, 1984,

-- SO-200-007, Revision 1, Daily Surveillance Operating Log, dated May 7, 1984,

-- Bechtel Drawings M-161 and M-2161, Liquid Radwaste Collection,

-- Safety Evaluation Report, NUREG-0776, dated April 1981,

-- Alarm Response Procedure AR-106-00, Revision 0, Alarm Response Window Box 06, dated December 8, 1983,

-- AR-107-001, Revision 0, Alarm Response Window Box 07, dated November 30, 1983,

-- AR-207-001, Revision 0, Alarm Response Window Box 207, dated March 19, 1984,

-- Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems", dated May 1973,

-- General Design Criterion 30, "Quality of Reactor Coolant Pressure Boundary" of Appendix A to 10 CFR 50.

The inspector reviewed the licensee surveillance procedures utilized to calculate the identified and unidentified reactor coolant system leakage inside containment. Technical Specification 3.4.3.1 requires the drywell floor drain sump level monitoring system to be operable and 3.4.3.2 requires unidentified leakage to be less than 5 gpm and total leakage to be less than 25 gpm. The surveillance procedures adequately calculate the leakage rates and meet the requirements of the Technical Specification.

The FSAR and licensee drawings were reviewed to determine if the calculation methods and associated instrumentation were consistent with the as-built system configuration. The values used in the surveillance procedures for tank capacities and leak rate conversions were consistent with the system configuration.

FSAR Section 5.2.5.3 incorrectly states that the total leakage rate limit for the reactor coolant system is established at 30 gpm. Technical Specification 3.4.3.2 actually requires leakage to be limited to 25 gpm total averaged over any 24 hour period. The inspector discussed the discrepancy with a licensee representative who stated that a FSAR correction would be submitted.

Several inconsistencies were also noted in the tank capacity figures referenced in the various documents. Drawings M-161 (Unit 1) and M-2161 (Unit 2) state that the Drywell Equipment Drain Tank "live" capacity is 1000 gallons. FSAR Table 9.3-10 states that the "live" capacity is 610 gallons and "nominal" capacity is 1060 gallons. FSAR Section 5.2.5 states that the useful capacity is 842 gallons. The inspector discussed the inconsistencies with licensee personnel who stated the items would be reviewed and the FSAR and drawings corrected as necessary. The correct capacity conversions are being utilized in the procedures.

The inspector reviewed several completed surveillances and the associated leakage rate calculations to verify that the surveillances were completed at the required frequency and that the test results met the Technical Specification requirements. The test data was accurate and complete, and met the applicable requirements. Action controls were implemented; and the equipment was verified to be properly returned to service.

The inspector concluded that the detection system provided reasonable assurance of detecting small leaks across the reactor coolant pressure boundary as required by General Design Criterion 30 and Regulatory Guide 1.45 and is acceptable.

5.0 Summary of Operating Events

5.1 Unit 1

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

Numerous minor recirculation pump speed oscillations occurred, the majority being on the B recirculation pump, causing small power changes. In each case the operators took manual control and locked the scoop tube. Extensive troubleshooting failed to identify a single specific cause. Corrective actions included replacing a millivolt converter card on the B recirculation pump controller, changeout of brushes on both recirculation MG sets, tightening of the scoop tube linkages, and adjustment of a binding set screw in the Bailey position transmitter. Since the completion of the corrective actions, no further oscillations have occurred.

On May 14, 1984, the RCIC system was placed out of service to correct a steam line drain alarm and to replace the turbine governor servo (EGM) which was suspected to be a contributor to the RCIC overspeed problems. The work was completed and the system returned to service on May 18, 1984. The inspector had no further questions on there items.

5.2 Unit 2

On May 8, 1984, initial criticality was achieved and startup testing began.

On May 10, 1984, plant heatup to 275 degrees commenced and the RPS shorting links were removed after SRM/IRM overlap was established.

On May 13, 1984, RCIC and ADS operability testing was completed suc cessfully. On May 17, HPCI was declared operable and plant pressure was increased above 150 psig.

On May 21, 1984, the unit reached rated temperature and pressure. Technical Specification LCO for RHR loops was entered due to excessive leakage on the B loop LPCI injection valve and faulty in-dication for the B loop LPCI injection testable check valve. (See detail 4.2).

On May 28, 1984, while pulling rods to open the No. 1 turbine by-pass valve in preparation for a RCIC test, pressure oscillations occurred which led to a power excursion exceeding the license limit of 5% power. (See detail 9.0).

After the power excursion event on May 28, the reactor was shutdown at 11:45 p.m., due to the time limitation for the Technical Specification LCO on RHR loops expiring, to make repairs to the leaking LPCI injection valve. Repairs were completed on the LPCI injection valve and turbine bypass valve during the outage lasting from May 28 - June 11, 1984.

6.0 IE Bulletins

IE Bulletin 84-02, Failures of General Electric Type HFA Relays in Use in Class 1E Safety Systems, was sent to the licensee for action on March 12, 1984. The bulletin requested licensees to inform the NRC about their plans, including schedules, for implementing GE recommendations to replace the nylon or Lexan coil spool type HFA relays, to provide information concerning their plans to upgrade surveillances on the affected systems, and to provide a written report.

The inspector reviewed the licensee's response, dated May 3, 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 submitted within the time period specified in the bulletin.

The licensee replaced all Class 1E HFA relays prior to fuel load on each unit. The Lexan coils were replaced with Tefzel coils, or the HFA relay itself was replaced with the Century Series HFA relay which contains a Tefzel coil. The replaced coils and relays were retained for spares for non-safety related applications.

This deficiency was previously reported to the NRC under 10 CFR 50.55(e) (Construction Deficiency Report 81-00-33).

The resolution of this issue was discussed in Inspection Reports 50-387/82-19 for Unit 1 and 50-388/84-13 for Unit 2 and found acceptable. Based on the licensee's response and previous NRC review of completed corrective action, the bulletin is closed.

7.0 Startup Test Program

7.1 Initial Criticality Witnessing

The inspector witnessed the activities associated with initial start-up of Unit 2 to ascertain conformance to license and procedural requirements, observe operating staff performance, and review the adequacy of test program records.

The inspectors attended Plant Operations Review Committee (PORC) Meeting No. 84-102 held on May 4, 1984, in preparation for initial criticality. The representatives for each section presented the status of their ability to support criticality to the committee, and all sections were ready to support the plant start-up. Several documentation items needed closing, and an additional PORC Meeting was held on May 5, 1984 to ensure all remaining items were completed or near resolution.

Rod withdrawal began at 7:21 p.m. on May 8, 1984 and criticality was achieved at 9:40 p.m. on May 8. Conditions during the startup were as expected. Criticality was achieved on Rod 18-43 (Group 3), Notch 8 on Step 78 of the procedure. Group 1 and 2 rods were fully withdrawn. Reactor coolant temperature was 112 degrees F. The predicted critical pattern was Step 81, six notches more than the actual critical rod pattern. The SRM period was between 60 and 100 seconds. The actual critical rod pattern was within the required acceptance criteria. The startup activities were also reviewed by a region-based specialist and are discussed further in NRC Inspection Report 50-388/84-21.

No unacceptable conditions were identified.

7.2 Heatup Phase Test Witnessing

The inspector witnessed portions of selected tests to verify that:

-- Procedures with appropriate revision were available and used;

-- Test changes were identified and implemented without changing the basic objectives of the test, in accordance with station procedures and Technical Specifications;

-- Prerequisites were completed and verified;

-- Initial conditions were met;

-- Special test equipment required by the procedures was utilized and calibrated;

-- Testing was performed in accordance with the procedure;

-- The results were satisfactory and met the acceptance criteria;

-- Test exceptions or deviations were identified, documented and reviewed.

7.2.1 ST 14.1 Condensate Storage Tank Injection

On May 29, 1984, the inspector witnessed Startup Test ST 14.1, Revision 3, Condensate Storage Tank Injection. The test was performed at rated reactor pressure and with reactor power level sufficient to provide steam for the RCIC turbine without a decrease in reactor pressure. One Turbine Bypass Valve was open at least 20% prior to RCIC operation. The test consisted of a manual start and automatic initiation with the RCIC pump taking suction from and discharging to the Condensate Storage Tank (CST).

During the manual start test, system stability was demonstrated by demanding step changes with the RCIC flow controller in both the manual and automatic mode. The system was operated for two hours after the automatic start to demonstrate continous operation of the system at equilibrium conditions. Although the system functioned properly during the test, several minor test exceptions were issued against the test and the test will be rerun at a later date. The test was performed satisfactorily and no unacceptable conditions were noted.

7.2.2 ST 25.1 MSIV Functional Test

On May 22, 1984, the inspector witnessed Startup Test ST 25.1, Revision 3, Main Steam Isolation Valve (MSIV) Functional Test. MSIV closure time testing was conducted at rated pressure. Closing time for each MSIV and the transient response of reactor variables were monitored. The closure time for each MSIV was required to be between 3.0 and 5.0 seconds. All of the MSIV's witnessed by the inspectors met the timing acceptance criteria and no unacceptable conditions were noted.

8.0 TMI Action Plan Requirements

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

8.1 II.K.3.25 - Effects of Loss of AC Power on Recirculation Pump Seals

By letter dated January 19, 1984, NRR notified the licensee that NRC had accepted the BWR Owner's Group position that Byron Jackson pump seals are adequate to meet the requirements of TMI Item II.K.3.25 and hence no modifications are required to the Susquehanna recirculation pump seal power supply. However, the licensee had previously made a modification to provide backup cooling to the pump seals. This item is closed.

8.2 I.D.1 - Control Room Design Review

On June 4, 1984, the inspector performed a walkdown of the Unit 2 control room and reviewed the corrective action taken on the human engineering deficiencies (HED's) noted in Inspection Report 50-388/84-08.

Based on the walkdown and discussions with licensee personnel, the inspector verified that the remaining items had been corrected and satisfied License Condition 4a, Attachment 1, for the Unit 2 license.

9.0 Transient Above 5% Power Limit

At approximately 1:00 a.m. on May 28, 1984, Unit 2 was operating at about 2% rated power and experienced a transient due to malfunctions in the secondary steam jet air ejector pressure regulator and #1 turbine bypass valve (BPV). The transient lasted approximately three minutes and an estimated peak power of 5.9% was reached. The transient began when the operator pulled rods to increase reactor power such that #1 BPV would further open from 25% to approximately 50% as a prerequisite for conducting a Reactor Core Isolation Cooling (RCIC) hot functional test. While pulling rods, the operator observed steam dilution valve cycling. This abrupt isolation of steam flow (10,000 lbm/hr) was followed by a steam pressure increase and the #1 BPV opened nearly full open to mitigate the pressure increase. Reactor pressure then dropped rapidly from about 920 psig to approximately 896 psig. This pressure decrease caused a reactor vessel level swell to about 53 inches from an initial level of 32 inches. After the swell, level dropped below the level setpoint of 32 inches and feed flow, controlled by vessel level only, increased from an average level of about 1,000 gallons per minute (gpm) to a maximum of about 1,800 gpm. This relatively large injection of cold feedwater to the reactor vessel added positive reactivity due to the negative moderator temperature coefficient. The positive reactivity addition resulted in a power and pressure increase to a conservatively determined peak of about 5.9% and 926 psig respectively. When pressure increased above the electro-hydraulic control (EHC) system set pressure of 920 psig, #1 and #2 BPVs opened reducing pressure and power. Additionally, at approximately the same time, the operator took manual control of feed flow and began inserting rods. The plant stabilized at approximately 1:03:40 with #1 BPV controlling reactor pressure at 920 psig and reactor power, vessel level, and feed flow stable. A sequence of events of this transient based on the process computer history data is as follows:

1:00:30	Commenced rod withdrawal to open #1 BPV to 50% open, BPV and steam dilution valves oscillating
1:01:00	Offgas steam flow isolates on low steam dilution flow #1 BPV opens nearly full open
1:01:15	Reactor pressure rapidly decreases from 920 psig to 896 psig. Vessel level swells to 53 inches and #1 BPV rapidly shuts as pressure drops.
1:01:20	Feed flow increases from an initial level of about 1,000 gpm to maximum level of about 1,800 gpm; pressure begins increasing.
1:01:45	Rx power increases to conservatively determined peak of about 5.9%. Pressure at maximum of 926 psig. #1 and #2 BPV open to reduce reactor pressure.
1:01:50	Pressure and power decreasing; oscillations in pressure and power continue as BPVs try to control pressure.
1:03:40	Plant is stable at approximately 2% power.

The licensee notified the NRC of this event via the Emergency Notification System at 1:59 a.m.

There is some uncertainty concerning the actual core power level reached during this event. The highest observed average power range monitor (APRM) reading was 11 on channel B which, when divided by the Gain Adjustment Factor (GAF) of 1.85 for that channel, corresponds to a power level of 5.9%. A rod block signal was also received. That signal was set at 11% on all APRM channels. Scram signals, which were set at 14% on APRM channels, were not received. Based on the GAFs, scram signals should have been received at APRM levels between 5.9 and 7.6%. Since none were received, a conservative upper bound of power level reached is about 5.9%. This level also corresponds to the Intermediate Range Monitor recorded levels during the power peak.

The inspector analyzed the event and reviewed plant records including: (1) the process computer history file; (2) shift supervisor, plant control operator and startup test logs for May 28; (3) manually plotted curves of the transient; (4) approved testing schedule; and (5) Significant Operating Occurrence Report 2-84-112. The GE Transient Analysis Recording System was not available during this event since it was being lined up to support RCIC testing. In addition, the inspector discussed the event with numerous licensee personnel, including the shift supervisor and unit supervisor on watch during the event. Based on the inspector's review, the initiating event appears to have been a malfunctioning of the secondary steam jet air ejector (SJAE) pressure regulator which caused oscillations in the steam dilution flow to the offgas steam (instrument root valves to this pressure regulator were later found to be shut).

In addition, the #1 BPV appeared to malfunction in that it was unable to control the reactor pressure transient caused by the rod withdrawal and isolation of the SJAE (as noted below, the valve subseqently stuck partially open). Hence, this event involved a transient caused by equipment malfunction which led to a power excursion conservatively considered to be above the license limit of 5% power. No engineered safeguards features or reactor protection system actuation setpoints were reached. No technical specification or procedural violations were identified. This event was also reviewed with the licensee at a meeting at Region I on May 31, 1984. The licensee filed a special report on this event to Region I on June 8, 1984. NRC Region I review concluded that the spatial power distribution for the entire core did not exceed 5% power.

At 5:30 a.m. on May 28, the licensee initiated a normal reactor shutdown because a seven day action statement on the B loop of Low Pressure Coolant Injection (LPCI) system was due to expire at 5:30 p.m. that afternoon. During the shutdown, the operators noticed that #1 BPV would not close further than 18% of its fully closed position. The licensee decided to halt the shutdown and troubleshoot the EHC system. At 11:05 a.m., while Instrument and Controls (I&C) technicians were troubleshooting EHC logic, the technician inadvertently caused a turbine trip signal to be sensed in the EHC system. The signal was apparently caused by a rapid reduction of a negative bias signal applied to try to further close the #1 BPV. The EHC system, in response to the turbine trip signal, rapidly opened and shut all BPVs. (#1 BPV did not fully shut). The resulting pressure transient caused vessel level to increase to approximately +60 inches and tripped off the operating reactor feed pump on high level (+54 inches). Vessel level decreased to approximately 18 inches before the feed pump and level were recovered. No RPS or ESF actuation setpoints were reached. Reactor power increased to about 3% from its initial level of about 2%. EHC trouble-shooting was stopped.

At 1:45 p.m. on May 28, the licensee manually scrammed the reactor to comply with the action statement requirements of Technical Specification 3.5.1.b.2 concerning the 'B' loop LPCI injection valve.

10.0 High Heatup Rate (Unit 1)

On February 21, 1984, during Unit 1 startup following the tie-in outage, the heatup rate in recirculation loop B appeared to exceed 100 Farenheit degrees in a one hour period. Between 6:30 a.m. and 7:30 a.m. on February 21, recirculation loop B temperature increased from 295 to 396 °F.; an increase of 101 degrees, per the Heatup/Cooldown Log (Attachment A to SO-100-011 dated February 21, 1984). The temperature increase in loop A during this period was 99 degrees . At the time of the event, the apparent high heatup rate was not noticed by the operator performing SO-100-011, nor was it noticed during subsequent review by the Unit Supervisor and Quality Control (QC). It was noted during a review by a staff engineer on May 9, 1984.

The inspector discussed this event with the licensee engineers and management and reviewed the following documents: (1) SO-100-011 dated February 21, 1984; (2) strip chart for Temperature Recorder TR1R650 for February 21, 1984; (3) Significant Operating Occurrence Report (SOOR) 1-84-223 dated May 9, 1984; and (4) Computer History File for February 21, 1984.

The high heatup rate occurred during the same time period in which 150 psig reactor pressure was exceeded without the High Pressure Coolant Injection (HPCI) system operable. The HPCI inoperability involved a violation of Technical Specifications and was reviewed as part of Special Inspection 50-387/84-11 conducted on February 20 - 24, 1984.

At the time that the high heatup rate was discovered, the computer history file was not available because of a magnetic tape problem. Subsequently, the licensee was able to retrieve the computer data which revealed that the 100 degree hourly limit was not exceeded. The inspector verified that the actual heatup rate was approximately 83 °F/hour since the actual recirculation loop B temperature recorded at approximately 7:30 a.m. was 378.6 °F. The plant heatup rate based on other plant temperatures, such as bottom head temperatures and vessel thermocouples, was also verified not to exceed the hourly limit; therefore, the Technical Specification heatup rate limit was not violated.

Nevertheless, the inadequate review of the Heatup/Cooldown Log is a concern. SO-100-011 requires recording the following parameters on the Heatup/Cooldown Log every 30 minutes during the heatup or cooldown: recirculation loop A and B temperatures, reactor pressure, and reactor vessel bottom head and bottom drain temperatures. The log requires the operator to verify, each time readings are taken, that 100 °F/hour is not exceeded. However, the log does not require the operator to calculate and record the temperature change. In response to this event, the licensee will increase the frequency of data recording to every 15 minutes and modify the data sheet to require calculation and recording of the temperature change after each data entry. In addition, better use of the process computer's capability for monitoring heatup rate will be made. These actions will provide an improved safeguard against excessive heatup/cooldown rates and allow better supervisory review of the data. SO-100-011 will be reviewed when it is revised. (387/84-22-02).

11.0 Exit Interview

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