U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/86-06; 50-388/86-04

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

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: March 15, 1986 - April 15, 1986

Inspectors: R. H. Jacobs, Senior Resident Inspector
L. R. Plisco, Resident Inspector

Approved By: Jack Strosnider 5/2/86
J. Strosnider, Chief, Reactor Projects Section 1B, DRP — date

Inspection Summary:

Areas Inspected: Routine resident inspection (U1 - 127 hours; U2 - 52 hours) of plant operations, licensee events, open items, surveillance, maintenance, and the Unit 1 Refueling Outage.

Results: The inspector noted that corrective maintenance is required on the 125 VDC Station Battery lighting system (Detail 2.2.1); an unusual event was declared due to a contaminated/injured man (Detail 3.1); an open states link was identified during the performance of the HPCI overspeed test (Detail 5.1); and post-maintenance testing of motor operated valve maintenance needs to be reviewed (Detail 5.2.1).

Three violations were identified. One violation concerned improperly controlled maintenance work in the reactor building recirculation plenum (Detail 5.2.2). The second violation concerned the inoperability of two SDV level transmitters (Detail 6.6). The third violation concerned SDV level transmitter isolation valves which were not locked open as required by station administrative controls (Detail 6.5).

8605130226 860507
PDR ADOCK 05000387
Q PDR

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Unresolved Item (388/84-34-14): Evaluate Diesel Generator Frequency Oscillations

During the Unit 2 Loss of All AC Power event in July 1984, the 'A' Emergency Diesel Generator (EDG) exhibited large frequency oscillations after a manual start and was subsequently manually tripped by the operator. Further testing of the diesel generator following the event could not reproduce the oscillations. The licensee issued scram recovery action item 2-84-04-21 to conduct a review of the EDG performance records to determine if there had been any previous problems with oscillations.

In Inspection Report 50-388/85-13, the inspector reviewed the licensee's assessment, which included recommendations for additional testing of the diesel generators. The site staff had not completed its evaluation of the recommendations at the time of the followup.

The licensee's corporate engineering staff recommended additional testing of the diesel generators in PLI-37643 dated January 14, 1985. The two monthly tests recommended were: (1) measuring the output of the governor load sensor with an amplifier during manual operation; and (2) measuring the resistance of the speed reference resistor used in emergency operation. Plant staff review of the recommendations found that the devices are currently tested in other surveillance procedures (18-Month Tests), and that due to the history of reliable operation of the devices, the increased testing frequency was not warranted. In addition the licensee recently performed modifications to the governor oil cooler, which should improve the governor response.

The inspector reviewed the associated surveillance tests and the recent results for indications of degradation. No unacceptable items were noted.

1.2 (Closed) Violation (388/85-06-07): Emergency Lighting Battery Power Supply Not 8-Hour Rated in Fire Zone 2-2A

In February 1985, the inspector identified that the emergency lighting battery power supply unit installed in the stairwell to the Remote Shutdown Panel at the 670 feet elevation of the Unit 2 Reactor Building (Fire Zone 2-2A, Core Spray Pump Room) did not meet the requirements of 10CFR50, Appendix R, Section III.J.

The installed light was manufactured by Exide, and was physically different from the Dual-Lite Model units used in other safety-related areas. On July 19, 1985 the non-conforming battery power supply was replaced with a Dual-Lite 8-hour unit under WA V50318. The NCR

85-0114 was subsequently closed. The inspector verified that the new light was installed.

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. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed. Nuclear Instrument panels and other reactor protection 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 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, Significant Operating Occurrence Reports (SOORs), and QA nonconformance reports. The inspector observed several shift turnovers during the period.

No unacceptable conditions were identified.

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, diesel generator building, ESSW pumphouse, and the plant perimeter. 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.

2.2.1 125 VDC Station Battery Lighting System

During a tour of the Unit 1 and Unit 2 reactor buildings on March 31, 1986, the inspector noted that some of the 125 VDC Station Battery Emergency lights were on, some were off, and some did not have light bulbs installed. The inspector reviewed lighting drawings EL-64 and the FSAR to determine the correct configuration requirements. FSAR Section 9.5.3 states that the 125 VDC lighting fixtures are normally energized from the normal AC subsystem, and automatically transfer to the 125 VDC system on loss of power. The FSAR also states that continued energization of the lamp with AC power during normal operation reduces the load on the battery chargers and maintains the lamp filament at a temperature that limits the initial current surge when the DC voltage is applied to the lamp, and also allows the lights be monitored continuously. It appears that corrective maintenance is required to ensure the emergency lighting system meets the FSAR commitments. Many of the areas needed to shutdown outside the control room currently do not have operable light fixtures. This item is unresolved. (387/86-06-01; 388/86-04-01)

3.0 Summary of Operating Events

3.1 Unit 1

Unit 1 continued with its second refueling outage which commenced on February 15, 1986. The Unit reached Operational Condition 4 on April 8, 1986. The outage activities are discussed in Detail 7.0.

The licensee declared an Unusual Event at 7:00 p.m., March 21, due to a contaminated injured man. The individual was replacing the control rod drive housing support underneath the reactor vessel when the platform grating gave way. He fell about 10 feet to the subpile floor injuring his right knee. He was in full protective clothing (PC) using a respirator, but some contamination soaked through the clothing. He was decontaminated prior to being sent off site. Contamination levels on the individual's skin were about 1-3K dpm/100cm^2 when he was transported via ambulance to the Berwick Hospital. The hospital had been alerted and was prepared to minimize contamination spread. An HP technician rode with the individual in the ambulance and an HP supervisor went to the hospital. The Unusual Event was terminated at 7:57 p.m. when the individual was transported to the hospital. He was completely deconned and all contaminated materials were brought back to the site. Surveys of the hospital and ambulance showed no spread of contamination. The individual is a PP&L employee and has a broken knee cap. Undervessel work was halted until an investigation was conducted and the grating reinforced.

On April 8, the annual emergency drill was held and involved full NRC participation. An assessment of the drill will be included in Inspection Report 50-387/86-07; 50-388/86-08.

3.2 Unit 2

Unit 2 operated at or near 100 percent power for most of the inspection period. Scheduled power reductions were conducted throughout the period for control rod pattern adjustments, surveillance testing, and scheduled maintenance.

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

*86-005, Reactor Building Ventilation Isolated on High Radiation Signal

86-006, Unplanned Engineered Safety Feature Actuation When 'States Link' Tightened

86-007, Division I LOCA Isolation Occurred Due to Blown Fuse

Unit 2

**86-004, Reactor Scram (Manual) Due to Main Transformer Overheating

*Previously discussed in Inspection Report 50-387/86-02; 50-388/86-01
**Previously discussed in Inspection Report 50-387/85-36; 50-388/85-32

4.2 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 they 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 report was reviewed:

-- Monthly Operating Report - March 1986, dated April 11, 1986.

The above report was found acceptable.

5.0 Monthly Surveillance and Maintenance Observations

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:

-- TP-152-006, HPCI Overspeed Trip Testing Using Auxiliary Steam, performed on April 7, 1986.

During the performance of TP-152-006 witnessed by the inspector on April 7, 1986, the HPCI turbine exceeded the acceptable overspeed trip setpoint of 5059-5265 RPM. The turbine tripped at 5289 RPM. After adjustments by mechanical maintenance, the test was reperformed successfully on April 8.

While setting up for the test, on April 7, I&C technicians were to open states links AA-5 and AA-8 in terminal panel TB1C016-A1 to defeat the low steam supply pressure isolation to HPCI. When the panel was opened, it was found that the links were already open, but no tags were on them. The system status file was searched, and no work was being performed which authorized opening these links. The licensee initiated SOOR 1-86-109 to investigate the cause. The results of the investigation will be reviewed in a subsequent inspection. (387/86-06-02)

5.2 Maintenance Activities

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

5.2.1 Motor Operated Valve Maintenance

On March 20, 1986, while performing SE-149-002, RHR Division II Logic System Functional Test, the recirculation system discharge bypass valve (1F032B) did not automatically close on receipt of a LOCA signal. This function is part of LPCI injection. The licensee investigated this occurrence and determined that a lead in the auto-closure logic was landed improperly at the motor operated valve (MOV). The lead was found terminated at terminal TB-82 and to correct the problem, the lead was moved to terminal TB-81. The valve was subsequently tested satisfactorily. Unit 1 was in Operational Condition 5 and the auto-closure function of this valve was not required to be operable.

The inspector reviewed this occurrence to determine its cause. This valve actuator had been recently worked for MOV environmental qualification (EQ) preventive maintenance (PM) under WA P-53156. The inspector reviewed this work package, electrical schematics E-151 sheet 14, M1-B31-275 (16) and connection drawings E-379. The inspector also reviewed work packages and applicable schematics for several other valves which received MOV EQ PMs this outage.

During the work performed on 1F032B, the actuator was determinated, disassembled, and reworked. All leads were removed from the limit and torque switch assemblies. Form MT-GM-021-2 was filled out with the required verifications for lead removal and installation. The form indicates that a lead was removed from and reinstalled to TB-82 (Cable #RK1Q1506E). E-151 sheet 14 and E-379, show that TB-82 is a spare limit switch contact. Apparently, the work group removing the lead on March 5 misread the termination number and the individuals reterminating the lead on March 7 put it back on TB-82 since it was indicated that this was the terminal from which it was removed. All other leads removed and reterminated matched the print. This error was not identified during post-maintenance testing of the valve. The only operational retest required after maintenance completion was to stroke and time the valve, verifying proper valve performance by control room indication. Since only the auto-closure function of the valve was disabled, the retest was inadequate to identify this problem. The work plan and Equipment Release Form did not require any further testing to declare the valve operational. However, due to the outage schedule, the system Logic System Functional Test (LSFT) was performed prior to declaring the recirculation or RHR system operational, although the LSFT was not required to be performed after this maintenance.

The licensee performed MOV EQ PMs on 37 valve actuators during this outage. These valves are in the RHR, Core Spray, HPCI, RCIC, RHRSW, RWCU and Feedwater systems. The inspector determined that in each case, according to the outage schedule, either the system LSFT was scheduled to be performed after completion of the valve maintenance or the valve does not have an auto-closure or opening function. Therefore, for this outage the adequacy of these valves following the EQ PMS is not a concern. However, the retest specified for the PM should be adequate for the work performed. The inspector discussed this issue with the Maintenance Supervisor who indicated they would review this. This issued is considered unresolved. (387/86-06-03)

5.2.2 Recirculation Plenum Work

On March 27, 1986, while observing maintenance on the reactor building recirculation plenum, the inspector noted that access hatches to both the recirculation fan supply and discharge sides of the recirculation plenum were open at the same time. Work was ongoing inside the upper (supply) portion of the plenum, but no work was ongoing on the discharge side. The inspector also noted that fuel movement was in progress on Unit 1 and no LCO had been entered for loss of secondary containment integrity. The inspector discussed this condition with the Unit 1 and Shift Supervisors. Both individuals were unaware that the plenum hatches were open. The work inside the recirculation plenum had been authorized by shift supervision with the understanding that the access hatch would be opened to allow ingress and egress only and that the access hatch would be replaced (although not tightened) while the work was underway.

Equipment Release Form (ERF) A-43692 was released at 7:45 a.m. March 27, to permit access to the recirculation plenum. The ERF stated that a man will be stationed at the hatch during the access period. It did not indicate that more than one hatch would be opened or that the hatch would only be opened for ingress and egress. As noted above, when the inspector observed that the access hatch to the lower plenum was opened, there was no one stationed at the hatch. The work in the plenum was authorized by WAs P60063 and P51875, and involved preventive maintenance on the recirculation fans and dampers. This work is normally performed during a two-unit outage when secondary containment is not required. This maintenance needed to be performed during this period to satisfy environmental qualification requirements.

The recirculation plenum houses the 'A' and 'B' recirculation fans and their isolation dampers. Upon receipt of any zone ventilation isolation signal, the recirculation fan in AUTO LEAD will start to recirculate the air in the isolated ventilation zones (I, II and/or III) to minimize the concentration of radioactive gases in the event of an accident. The Standby Gas Treatment System (SGTS) takes a suction on the discharge side of the plenum to maintain a negative pressure in the reactor building and filter the offsite release. If the recirculation fan in AUTO LEAD fails to develop 0.5 in. W.C. pressure across the fan, after a time delay, the running fan will stop and the standby fan will start. In this case, the standby fan (OV201A) was tagged out. Therefore, the two open hatches on the suction and discharge sides of the plenum would tend to equalize pressure across the fan and may have prevented the running fan from developing the required 0.5 in. W.C. If the running fan tripped off, there would be no recirculation flow. Previous experience has shown that without recirculation fans, the drawdown times for the SGTS system to drawdown to a 0.25 inch vacuum in the different ventilation zones, would be exceeded. Therefore, this condition may have degraded secondary containment integrity.

When the inspector notified the control room of the condition of the recirculation plenum, the Shift Supervisor immediately halted fuel movement. The work in the recirculation plenum was secured and the hatches reinstalled. Fuel movement was recommenced at 12:45 p.m. March 27. The maintenance supervisor indicated that both plenum hatches were open at the same time from approximately 10:00 a.m. to 12:00 a.m., a period of two hours. The licensee prepared a Significant Operating Occurrence Report (SOOR) to evaluate the incident.

Technical Specification 3.6.5.1 requires maintaining secondary containment integrity when the reactor is in Operational Conditions 1, 2, 3, or when fuel handling is in progress. In this case, Unit 2 was at power and fuel movements were ongoing in Unit 1. Opening and leaving open both recirculation plenum hatches for two hours degraded secondary containment integrity. This was contrary to the directions on the Equipment Release Form and the understanding of the operators. Since the operators were unaware of the condition of the recirculation plenum, no Limiting Condition for Operation was entered for not maintaining secondary containment integrity. The release of this work was inadequately controlled and is a violation of AD-QA-306, System/Equipment Release. (387/86-06-04)

6.0 Inoperable Scram Discharge Volume Level Transmitters

6.1 Summary of Event

On April 10, 1986, in Operational Condition 4, licensee I&C technicians noted contradictory scram discharge volume (SDV) level indications during an operational hydrostatic test. Subsequent investigation found that the isolation valves to two SDV level transmitters, which provide reactor protection system (RPS) signals, were closed. Further review identified that the valves had been closed since the installation of the level detectors in May 1985. The cause of the inoperable instruments was the inadequate close-out of a modification package. Due to the nature of the instrumentation circuits and the surveillance test requirements, the inoperable detectors would not have been detectable during normal plant operation.

6.2 System Description

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is filling up, but the volume is still great enough to accommodate the water from the movement of the rods when they are inserted. In addition, if at the completion of a scram the level of water in the scram discharge volume is greater than the trip setting, the RPS cannot be reset until the discharge volume has been drained.

Four nonindicating level float switches (one for each channel) provide scram discharge volume high water level inputs to the four RPS channels. Two switches are installed on each instrument volume. In addition, a level indicating switch (trip unit), with transmitter, in each channel provides redundancy with the level switches. This arrangement provides sensor diversity, as well as redundancy, to assure that no single event or common-mode failure could prevent a scram caused by SDV high water level. Both the four level transmitters and four float switches are required to be operable by Technical Specifications Table 3.3.1-1. All eight detectors have the same trip setpoint of 88 gallons and are calibrated on the same frequency (every 18 months).

IE Bulletin No. 80-17, "Failure of 76 of 185 Control Rods to Fully Insert During a Scram at a BWR", and the subsequent five supplements, described deficiencies with the SDV design. In response to the bulletin (PLA-770 dated May 26, 1981), the licensee stated that delta-pressure level switches would be installed to provide diversity for scram initiation. The commitment was included in the Unit 1 Operating License dated July 17, 1982, as License Condition 2.C.(17).

The License Condition stated that prior to startup following the first refueling outage, diverse and redundant SDV instrumentation for each instrumented volume, including both delta pressure sensors and float sensors, were to be incorporated into the scram discharge volume system.

Plant Modification Record (PMR) 82-578, which installed the level transmitters, was completed on May 2, 1985. A letter was also sent to NRR (PLA-2470) on May 20, 1985 stating that the design modifications required by the License Condition had been implemented.

6.3 Description of Event

On April 10, 1986 an operational leak test was in progress on Unit 1. The unit was in Operational Condition 4 and was nearing completion of the second refueling outage which commenced on February 15, 1986. As part of the surveillance test SE-100-002, ASME Class 1 Boundary System Leakage/Hydrostatic Pressure Testing, a full reactor scram was manually initiated from the control room. At approximately 11:00 a.m., I&C technicians who were performing unrelated work in the upper relay room, noted contradictory SDV level indications on panel 1C635. The A1 detector was indicating upscale high as expected, but the A2 detector was indicating downscale low. The technicians notified the control room and the discrepancy was investigated. Operators dispatched to the reactor building found valves 147F160C and D and 147F155C and D locked closed, thus isolating level transmitters LT-C12-1N016C and D from the instrument volume. As noted above, these level transmitters provide a reactor protection system scram signal on high level in the scram discharge volume. Further license review identified that the system checkoff list (COL) incorrectly required these valves to be locked closed. The valves for the other two level transmitters were found open, and were correctly aligned in the COL.

6.4 Licensee Investigation and Corrective Action

Following identification of the isolated level transmitters, the licensee took immediate corrective actions to realign the Unit 1 isolation valves and to verify the status of Unit 2, which was operating at 100 percent power. The checkoff list for Unit 1, CL-155-0012, was revised to restore the 'C' and 'D' level transmitters, and the valves were properly aligned. The level indications in the upper and lower relay panels were verified to be proper. The Unit 2 checkoff list was verified to be correct, and the isolation valves were physically checked to be in the proper position.

A Significant Operating Occurrence Report (SOOR 1-86-113) was issued to describe the event and to initiate an investigation and corrective action. The licensee evaluated the event and determined it not to be reportable in accordance with 10 CFR 50.72.

On April 20, 1985, during the Unit 1 first refueling outage, the Control Rod Drive Hydraulic System was lined up by operations checkoff list COL-OP-155-001-2, Revision 4. This valve lineup listed the "normal position" for the eight level transmitter isolation valves as locked closed. The valves were locked closed in the COL because the modification to install the level transmitters had been only partially completed, and this incomplete installation was to be isolated from the instrument volume. The modification PMR 82-578, was completed and declared operational on May 2, 1985.

Prior to declaring a system operable, the modification process requires the completion of Operational Readiness Form AD-QA-410-8. The form requires that the Operations section head sign the checklist to indicate that the required actions are complete. One of the required actions includes updating operating procedures. This section of the form was signed on May 2, 1985. Licensee review, following the event, identified that during the modification closeout process, the operations section did not identify that the COL needed to be revised to place the new level transmitters into service. The Document Review sheet, Form AD-QA-410-3, completed by the responsible engineer did not list any operating procedures that required revision. This was also true for the OMISS Abstract. Both of these documents should have noted that the COL needed revision, and normally would have alerted the Operations section that a change was required.

The level transmitter modification was reviewed and closed out on May 2, 1985. Later the same day, members of the control room operating staff noted that the valves were still closed on the COL, and a procedure change, (PCAF 1-85-562) was issued to open the isolation valves for the 'A' and 'B' detectors. The PCAF did not address the 'C' and 'D' transmitters. During the investigation it could not be determined why the other two detectors were not realigned, but it appears there may have been a drawing error at the time which showed the 'C' and 'D' detector valves already locked open.

Although the licensee investigation was not complete by the end of the inspection period, the root cause appears to be the inadequate closeout of the completed modification.

6.5 <u>NRC Followup Review</u>

The inspectors reviewed the operating procedures, checkoff lists, surveillance procedures, system drawings and the modification package related to the scram discharge volume to determine the cause of the isolated valves and to determine whether the inoperability should have been detected previously.

Inspector review of the modification package and applicable documents confirmed the licensee's findings. As discussed in section 6.4, the cause of the isolated level detectors appears to be an error made in the closeout of the SDV modification package.

The level transmitters are required by Technical Specifications to have a monthly functional and 18-month calibration surveillance test performed on them. The monthly functional test consists of injecting a signal into the circuit in the relay room to verify the circuit response. The isolation valves are not manipulated during this test, and the level transmitter is not disturbed. The 18 month surveillance test requires the manipulation of the transmitter isolation valves, but since the system had just been placed in service in May 1985, this surveillance test had not yet been performed. It is possible that this inoperability would have been identified during the calibration procedure which is scheduled for November 1986. All of the surveillance tests performed on the isolated detectors met the acceptance criteria. The post-modification testing that was performed also did not verify that the level transmitters were connected to the process.

The system schematic diagrams were reviewed to determine if the post-trip review process, following one of the three reactor scrams during this period, should have detected the inoperability of the level transmitters. The level transmitters provide inputs to the RPS trip system, SDV high level alarms, and plant computer points. The inputs to the RPS system are in series with the float switch inputs, so that as long as the float switches operate properly, the RPS system will respond as designed on a SDV high level condition. The alarm and computer point contacts are in parallel so that any input will provide the indication. Due to this circuit configuration, the inoperability of the transmitters could not have been detected by control room indications or the plant computer printouts. The only direct indication available is the level meters in the relay room, which would only indicate during a scram.

The inspectors conducted a walkdown of the Unit 1 and Unit 2 SDV installations. Several discrepancies were identified with the Unit 2 COL and drawings. Administrative procedure AD-QA-302, System Status and Equipment Control, states that root valves (first valves off process line) that supply safety related instrumentation will be locked open. During the walkdown of the Unit 2 system it was noted that four of the isolation (root) valves were not locked open, as were the other twelve valves. The checkoff list CL-255-0012 also listed these valves (247155A, B, C, and D) as open rather than locked open. This does not appear to be consistent with the administrative procedure. The system drawing was also incorrect. P&ID M-2147 shows that isolation valves 247F115A & B and 247F160A & B are locked closed while they should be locked open. This item is a violation. (388/86-04-02)

6.6 Technical Specification Adherence

Technical Specification Limiting Condition for Operation (LCO) 3.3.1 requires that during Operational Conditions 1, 2, and 5 (with any control rod withdrawn), the reactor protection system instrumentation

channels for the scram discharge volume high water level transmitters be operable. Table 3.3.1-2 states that two operable channels per trip system are the minimum required.

With the number of operable channels less than the required Minimum operable channels per trip system, for both trip systems, at least one trip system is to be placed in the tripped condition within 1 hour and the unit is to be in at least Hot Shutdown within 12 hours (if starting in Operational Condition 1 or 2).

Contrary to the above, between April 20, 1985 and April 10, 1986 two scram discharge volume high water level transmitters were inoperable, in that their isolation valves were shut. This is a violation. (387/86-06-05)

6.7 Safety Significance

As described in section 6.2, the two level transmitters that were found isolated provide inputs to the reactor protection system. One detector from each RPS trip system was affected. The remaining two level transmitters, one per division, were sufficient to provide a reactor scram signal on high scram discharge volume water level, assuming no single failure. In addition, the four float switches, which provide diverse and redundant initiation signals were operable. Inspector review of completed surveillance tests verified that the float switches were operable, and that there has not been a history of failures of these detectors.

Each SDV instrument volume is monitored by two other level detectors, which provide alarm functions. One float switch on each volume provides a "not drained" alarm, and another provides a Rod Block Signal. The four high level float switches also provide a high level alarm, in addition to the RPS signal. Therefore, if any leakage had occurred, it would have been annunciated in the control room. During normal operation the SDV vent and drain valves are open, allowing any leakage to drain from the volume.

The level transmitters were installed during the Unit 1 first refueling outage in May 1985. Therefore, the unit did operate safely, and in accordance with Technical Specifications, for approximately three years with only the four float switches operable. The objective of the design modification which installed the additional transmitters was to provide diversity, so that a single random failure or potential common cause failures could be accomodated. Investigations and test performed by BWR licensees have shown that crud buildup, human error, manufacturing defects, hydrodynamic forces and environmental concerns have led to past common-cause failures with the float switches. The level transmitters were added to the Technical Specifications by the licensee following the modification.

Although the isolation of the level transmitters appears to be of minimal safety consequence, the adequacy of the closeout and testing of safety-related modifications must be viewed as a safety concern. Since the same controls are used on other safety-related modification activities, this area should be addressed in the licensee's corrective action.

6.8 Summary of Findings

-- Technical Specification 3.3.1, which requires four SDV level transmitters to be operable in Operational Conditions 1, 2, and 5, was violated. The valves to two of the level transmitters were isolated on April 20, 1985, and Unit 1 operated from June 8, 1985 until February 15, 1986 when the unit shutdown for a refueling outage. (There were three short forced outages during the period). The isolated valves were discovered on April 10, 1986.

-- The level transmitters were left isolated after the completion of a modification due to a failure in the modification closeout process. The checkoff list was not revised during the closeout process, and the operating procedures were not identified as needing revision on the Document Review Form, or the OMISS abstract. Two of the detectors were later valved in when identified by operations personnel. The closeout process needs to be reviewed for adequacy. Post-modification testing did not verify that the detectors were connected to the process.

-- Due to the configuration of the SDV level circuitry and indication, the licensee could not have been expected to identify the isolated detectors during normal plant operation. The SDV high level alarm contacts are paralleled with the float switch contacts so that either device will actuate the alarm. Therefore, if the float switches responded as designed, the failure of the level transmitter would be masked. The same type of circuitry exists for the computer points. Review of the post-trip data would not have shown any abnormal occurrences. The level transmitter indication in the relay room, observed during a scram, was the only method to identify the isolated detector. The closed valves would have been manipulated by the 18-month calibration procedure, but it was not due to be performed until November 1986.

-- Since the isolated level transmitters provided redundant signals, and the four float switches were fully operable, the fact that the detectors were inoperable appears to be of minimal safety significance. The unit operated for approximately three years prior to the installation of the level transmitters.

-- Several procedural and drawing problems were noted during the investigation. Although the station administrative procedures require that instrument root valves be locked open, the Unit 2 checkoff list did not lock open all of the level transmitter isolation valves. In addition, the Unit 2 system drawing, P&ID M-2147, incorrectly stated that four of the isolation valves were normally locked closed. The valves were found in the correct position.

-- The licensee investigation has not been completed and more information may become available at a later date. This will be reviewed during a later inspection.

7.0 Unit 1 Refueling Outage Activities

7.1 Refueling Outage Summary

During this period, Unit 1 continued its second refueling outage which began February 15, 1986. Major outage work during this period consisted of restoration of Division I systems, bulk work and restoration of Division II systems, refueling, integrated system testing, and preparations for startup. It was noted in the last report period, that some linear indications were identified on the steam dryer and support block during in-vessel inspections. These indications did not require repair. Refueling began on March 21 and was completed March 28. Due to an excessive number of failures of snubbers, the licensee was required to remove and test more than 1000 snubbers. Outage critical path time was not impacted. Following refueling completion, 4KV bus outages were conducted to install a degraded grid voltage modification. The bus outages were followed by loss of offsite power and LOCA testing which was completed April 7. The reactor vessel head was reinstalled and Operational Condition 4 entered on April 8. The Operational hydrostatic test was completed on April 11. Leaks identified during the test, including leaks in the reactor vessel head piping and two control rod drives, were repaired. At the end of the report period, the outage was still on schedule with reactor startup expected to occur on April 18.

7.2 Design Changes and Modifications

The inspector observed portions of selected modification activities to determine that: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative reviews and approvals were obtained prior to initiating the work; the installation conformed to the drawings and other design documents; activities were conducted using formal work control procedures; and QC hold points were established where required.

Portions of the following activities were observed:

-- PMR 84-3113, Degraded Grid Voltage Protection, performed under CWO C51225 on March 21, 1986 (1A202 4KV Bus).

No unacceptable conditions were identified.

7.3 Complex Surveillance Test Witnessing

The inspector observed the performance of portions of certain complex 18-Month Surveillance tests to determine that: the Technical Specification (TS) surveillance requirement was covered by an approved procedure; that prerequisites were completed; special test equipment was calibrated; required data was accurately recorded; appropriate revision of the test procedure was available and in use by test personnel; system restoration was accomplished upon completion of testing; and the surveillance was performed within the time frequency specified by the Technical Specifications.

Portions of the following tests were observed:

-- SE-124-C02, 18-Month Diesel Generator 'C' Auto Start and ESS Bus 1C Energization on Loss of Offsite Power - Plant Shutdown, performed on April 4, 1986.

-- SE-124-D02, 18-Month Diesel Generator 'D' Auto Start and ESS Bus 1D Energization on Loss of Offsite Power - Plant Shutdown, performed on April 7, 1986.

-- SE-124-207, 18-Month Diesel Generators 'B' and 'D' Auto Start and ESS Buses 1B and 1D Energization on Loss of Offsite Power with a LOCA - Plant Shutdown, performed on April 7, 1986.

-- SE-124-107, 18-Month Diesel Generators 'A' and 'C' Auto Start and ESS Buses 1A and 1C Energization on Loss of Offsite Power with a LOCA - Plant Shutdown, performed on April 5, 1986.

The following items were noted:

-- During the performance of SE-124-107, the 'C' ESW pump did not start automatically as designed. In addition, the 'C' ESW pump and 1A RHRSW pump could not be manually started from the control room. Licensee investigation later found that relay 44AX1 had not picked up. It was replaced. A data review following the test found that timing relay 62A-20302 for the 1C RHR pump was out of tolerance. It was also repaired.

-- During SE-124-D02, the inspector noted that speed oscillations occurred on the 'D' diesel generator following the shutdown of the RHR pump. Frequency decreased to approximately 58.5 several times before the test was completed.

-- During the performance of SE-124-C02, the inspector noted some discrepancies with the procedure changes that were issued prior to the test. PCAF 1-86-486 added an additional prerequisite for the test, but the step was not added to Attachment A for signing for completion of the prerequisite. The change added ventilation fan 1V210C (RHR Pump Room Unit Cooler) since drywell cooling fan 1V414A was out of service. Just prior to starting the test, the inspector discussed the discrepancy with the test director, who then noted the error in the PCAF. In addition, the PCAF had not been properly incorporated into the procedure. The test director then issued a new PCAF to the procedure and had the additional fan started as required. The inspector had no further concerns.

8.0 Allegation - Dravo, QC

On March 31, the inspector received an allegation via telephone from a recently terminated Dravo, Inc. QC inspector. Dravo, Inc. is the constructor for the fifth diesel generator (D/G) project. The individual indicated that he had been terminated for refusing to perform an inspection on bolts to be used with Unistrut supports. He indicated that he refused to perform the inspection because a Non-Conformance Report (NCR) was outstanding, relating to the bolts. His concern was that Dravo improperly used a Gibbs & Hill document to authorize cutting of the bolts, and questioned whether it was acceptable to cut these bolts.

The inspector reviewed NCR Number 361, Construction Site Procedures (CSP) 8.1 "Non-Conformance Reports", CSP 8.4 "Configuration Control and Information Request", Quality Control Procedure (QCP) A-10 "Control of Nonconforming Items", and Information Request (IR) PP&L-009. The inspector also discussed this incident with the PP&L Assistant QA manager for the fifth D/G project, the Dravo, Inc. QC Site Supervisor and a PP&L engineer. On February 27, 1986, Information Request PP&L-009 was issued requesting permission to cut 1/2"-13 x 1 3/16" and 1/2"-13 x 1 1/2" bolts to a length of 1/2" and 15/16" respectively. The bolts were to be used with Unistruts and were too long. On February 27, the IR was resolved indicating that the bolts could be cut. The IR was written on a Gibbs & Hill (G&H) IR form. The nonconformance specified on NCR #361 dated March 25, 1986 was that IR PP&L-009 was prepared on the wrong form (Attachment C rather than Attachment F to CSP 8.4). The NCR specified that this was nonconforming because the approval authorities and distribution are different. The NCR was dispositioned "use-as-is" on March 26 based on the fact that it was an isolated case and that the IR was properly dispositioned by PP&L Nuclear Plant Engineering. However, the NCR was apparently not dispositioned at the time the individual refused to perform the inspection.

In reality, the PP&L and Gibbs & Hill IR forms are virtually identical forms. The incorrect form was used but was processed in accordance with procedure. The NCR originator and the NCR log indicated that a "Hold" Tag was not issued for this NCR. Therefore, no equipment was placed in a "hold" status. The governing procedures, QCP A-10 and CSP 8.1, however, do not recognize issuance of an NCR without a "hold" tag although the procedures do not explicitly state that NCRs must use "hold" tags. Since this issue does not relate to the safety impact of the allegation, it will not be further addresssed.

The potential safety concern relates to use of the cut bolts. Since the bolts were only shortened, the strength properties of the bolt are not affected. The bolts were to be used in Unistrut as part of a conduit support and the bolts would be engaged with a spring nut. PP&L engineering, which was the proper design authority, approved the cutting and use in this application. The inspector reviewed PP&L Specification C-1055, "Technical Specification for Routing and Installation of Conduit and Conduit Supports in the 'E' Diesel Generator Building", which indicates that 1/2" diameter bolts are acceptable for this application and the specification does not preclude bolt cutting. Therefore, there is no safety concern with the use of these bolts. This allegation is closed.

9.0 Reactor High Pressure Switch Head Connection

On March 6, 1986 during the current Unit 1 refueling outage, the licensee identified that the head correction calculations of PS-B21-1N023A, B, C, D (Unit 1 reactor vessel steam dome pressure switches) were in error. These pressure switches provide input to the reactor protection system (RPS) to scram the reactor on high pressure. The head correction calculational error was in the non-conservative direction by 9.7 psig. The nominal trip setting in the Technical Specifications (TS) is 1037 psig. The allowable value is 1057 psig. The licensee reviewed past calibration data from 1982 to the present and identified no cases in which the unit was operated with the pressure switch setting exceeding the Technical Specification allowable value due to this head correction error. The calculational error did cause the "As Left" setting of the switches following a calibration to be in excess of the nominal trip setting of 1037 psig on many occasions. The surveillance procedure, SI-158-303, specifies an "As Left" value for these switches to be less than or equal to the nominal trip setting, so that between calibrations, instrument drift should not cause the pressure switch setting to exceed the allowable valves. However, since the allowable value was not exceeded, no Technical Specification violation occurred.

The head correction calculation error resulted from using an improper elevation for the pressure switches. The licensee reviewed head correction calculations for the corresponding Unit 2 pressure switches and 50 other Unit 1 and Unit 2 instruments. No other discrepancies were identified. The inspector reviewed portions of the pressure switch surveillance data and elevation data for other instruments and identified no discrepancies. The calculations were performed by the same individual and appear to be isolated occurrences. The inspector had no further concerns.

10.0 Exit Meeting

On April 18, 1986 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.