APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-382/90-19   Operating License: NPF-38

Docket: 50-382

Licensee: Entergy Operations, Inc.
P.O. Box B
Killona, Louisiana 70066

Facility Name: Waterford Steam Electric Station, Unit 3 (Waterford 3)

Inspection At: Taft, Louisiana

Inspection Conducted: July 16 through September 4, 1990

Inspectors: W. F. Smith, Senior Resident Inspector
Project Section A, Division of Reactor Projects

S. D. Butler, Resident Inspector
Project Section A, Division of Reactor Projects

M. E. Murphy, Reactor Inspector
Test Programs Section, Division of Reactor Safety

Approved: T. F. Westerman   9-18-90
T. F. Westerman, Chief, Project Section A   Date

Inspection Summary

Inspection Conducted July 16 through September 4, 1990 (Report 50-382/90-19)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events, monthly maintenance observation, monthly surveillance observation, operational safety verification, followup of previously identified items, licensee event report followup, and fire protection program followup.

Results: One violation was identified in Paragraph 6, involving failure of a security officer to follow plant security procedures. On August 9, 1990, while processing NRC visitors through the primary access point, two visitors not authorized for unescorted access were permitted to enter the protected area unescorted. Since the visitors were NRC personnel with valid security clearances and were observed by the escort at all times, there was minimal safety significance to the incident. Also, in view of the licensee's prompt and thorough corrective action taken once the violation was identified by the inspector, no citation was issued, as permitted by the NRC's Enforcement Policy.

Inspections were conducted by the resident inspectors in response to two offsite power disturbances, one resulting in a reactor trip on August 25, 1990, and the other resulting in a successful reactor cutback which enabled the plant to avoid safety system challenges. The licensee's performance in recovering from both instances was excellent. The plant was maintained in a safe condition, the systems involved performed as designed, and corrective actions appeared appropriate. The reactor trip was the second this year involving offsite power disturbances and lockout of the steam bypass control system (SBCS). The licensee initiated a design change to reduce the vulnerability of the SBCS to such disturbances. This is discussed in detail in paragraph 3.b.

Maintenance and surveillance activities continued to show improvement as the licensee's procedure upgrade and compliance programs were implemented. Minor procedure step signoff problems indicated that there was still insufficient guidance in the field. This is discussed in paragraph 5.a.

The fire protection program followup inspection discussed in paragraph 9 did not identify any violations or deviations. The inspector noted that progress in completing the correction of deficiencies appeared to be slow. However, in view of the large scope of this effort, the inaccessibility of many of the fire barriers while operating the plant, and the compensatory actions (fire watches) taken by the licensee, there was no safety concern.

DETAILS

1. Persons Contacted

Principal Licensee Employees

R. P. Barkhurst, Vice President Operations
*J. R. McGaha, General Manager, Plant Operations
*P. V. Prasankumar, Technical Services Manager
D. F. Packer, Operations and Maintenance Manager
A. S. Lockhart, Quality Assurance Manager
*D. E. Baker, Director, Operations Support and Assessments
*R. G. Azzarello, Director, Engineering and Construction
W. T. Labonte, Radiation Protection Superintendent
*G. M. Davis, Events Analysis Reporting & Response Manager
R. F. Burski, Director, Nuclear Safety
*L. W. Laughlin, Site Licensing Supervisor
*J. G. Hoffpauir, Maintenance Superintendent
R. S. Starkey, Operations Superintendent
A. G. Larsen, Assistant Maintenance Superintendent, Electrical
D. T. Dormady, Assistant Maintenance Superintendent, Mechanical
D. C. Matheny, Assistant Maintenance Superintendent, Instrumentation and Controls
*R. W. Lailheugue, Administration Manager

*Present at exit interview.

Also present at the exit interview was Ms. M. L. McLean, Physical Security Specialist, NRC Region IV.

In addition to the above personnel, the inspectors held discussions with various operations, engineering, technical support, maintenance, and administrative members of the licensee's staff.

2. Plant Status (71707)

During the majority of the reporting period, the plant was operated at full power. A power reduction to 90 percent was required on August 11, 1990, to support routine surveillance tests of turbine valves and control element assemblies. On August 25, the plant tripped due to a lightning strike in the 230 Kilovolt (KV) switchyard (see paragraph 3.b. for details). The plant was restarted on August 27 and returned to full power on August 28. After a brief power reduction to 90 percent that afternoon to repair a leaking relief valve on the 4A feedwater heater, the plant operated at full power until September 4, when the unit experienced a generator/turbine trip during a thunderstorm (see paragraph 3.c for details). The subsequent reactor power cutback followed by operator actions reduced power to approximately 18 percent, where the unit remained until the end of this inspection period.

3. Onsite Followup of Events (93702)

a. Inadvertent Engineered Safety Feature (ESF) Actuations

During the reporting period, the licensee experienced four inadvertent ESF actuations. These actuations were of the control room emergency filtration unit and occurred on July 21 and August 5, 9, and 12, 1990. In each instance, the actuations were related to failures of the control room outside air intake (CROAI) radiation monitors. The actuations were promptly reported to the NRC as required by 10 CFR 50.72 and the details of the events were reported in LER 382/90-011. In each instance, the licensee verified that no detectable activity existed at the control room air intakes. The licensee determined that in two of the events (July 12 and August 9), the actuation of the CROAI radiation monitors was caused by damage to the detector's aluminum foil beta shield, which allowed exposure of the detector to light. The beta shield damage, caused by aging, corrosion, and mechanical damage due to air flow and dust, had been a recurring problem. The licensee initiated a design change (DC 3078) to replace the shields with a protective bracket and mylar window to make it more resistant to damage. The licensee committed to complete the modifications by January 15, 1991, but the work was in progress and was expected to be completed before the end of September 1990. Troubleshooting of the CROAI radiation monitor which caused the actuations on August 5 and August 12 did not reveal any identifiable problems but several electrical components in the monitor were replaced and the problem has not recurred. Completion of the licensee's corrective actions for these inadvertent ESF actuations will be verified during closeout of LER 382/90-011.

b. Reactor Trip due to Fault on Offsite Power

At 6:02 p.m., on August 25, 1990, during a severe thunderstorm, a fire occurred in the 230 KV offsite power switchyard, and the reactor tripped from full power on high pressurizer pressure due to the power disturbance. All safety systems responded normally; however, the nonsafety-related SBCS and reactor cutback system did not function to permit the load rejection without tripping the reactor or opening main steam safety valves.

As a result of the disturbance on offsite power, the main turbine load drop anticipator sensed a mismatch between low pressure turbine power and main generator output, thus shutting the governor and intercept valves. This feature was designed to protect the main generator from overspeeding and overrunning the grid. The megawatt output value decreased momentarily when the fault decreased offsite voltage. The same disturbance caused the SBCS to lock out and, since reactor cutback responds to SBCS, a cutback did not occur. Both the SBCS and cutback were powered from a 120 VAC power distribution panel, which in turn was powered from an A train vital motor control center. The SBCS was designed with a feature that locks out the system if it senses low voltage. The SBCS will not function when voltage is restored unless an operator manually resets the system and all logic is satisfied for operation. Consequently, reactor coolant system pressure increased to a peak pressure of 2360 psia, which is above the reactor trip setpoint. The main steam safety valves lifted and reseated as designed. A turbine trip and emergency feedwater actuation followed as designed.

The two Waterford 3 offsite power sources, Line A and Line B, were both supplied by the 230 KV switchyard east and west busses. During the thunderstorm, an electrical fault occurred on the east bus. The switchyard protective controls attempted to isolate the fault by stripping the loads and power sources from the bus. Waterford 3 was successfully removed, leaving both Lines A and B tied to the west bus only. However, middle-phase Oil Circuit Breaker (OCB) S7166 connecting Waterford 1, a gas burning power plant, ruptured, propelling itself off its foundation about 25 feet. The bottom of the OCB also blew off, propelling itself another 50 feet, releasing over 2000 gallons of oil, which caught fire. The fire and missiles also damaged a number of insulators and disconnects. The smoke was sighted by Waterford 3 watchstanders at 6:16 p.m., and by 6:31 the licensee called the local fire department for assistance. An unusual event was declared at that time, in accordance with the licensee's emergency plan. The appropriate local authorities and the NRC were notified as required. At 6:51 p.m., Southern Controls opened OCB S7172 to further isolate the fire. This deenergized Line A offsite power to Waterford 3. Emergency Diesel Generator A started as designed and assumed the appropriate Class 1E loads. At 7:32 p.m., the fire was extinguished and, at 8:46 p.m., offsite power was restored to Line A. At 8:57 p.m., the unusual event was terminated.

The inspector expressed concern that the vulnerability of the nonsafety-related SBCS-to-line voltage fluctuations appeared to be causing unnecessary challenges to safety features. This was the second time this year a grid disturbance locked out the SBCS. The other lockout occurred on March 29, 1990, under similar circumstances (see LER 382/90-003). The licensee agreed that the design could be improved by connecting the SBCS and cutback system to an uninterruptable power supply and that a design change request was being initiated. The licensee explained that the current design is based on the premise that if offsite power is lost there will be no vacuum in the main condenser to accommodate the SBCS output. Therefore, it appeared inappropriate to have this additional load on an uninterruptable power supply. Momentary disruptions were not considered. The inspectors will follow up on the licensee's design change request through implementation (Inspector Followup Item 382/9019-01).

c. Reactor Cutback due to Offsite Power Disturbance

On September 4, 1990, at 9:20 p.m., the plant experienced a reactor power cutback from 100 percent power during a severe thunderstorm. A generator/turbine trip was caused by actuation of the sudden pressure relay on the A main transformer. The SBCS actuated due to the large load rejection and initiated the cutback. Reactor power reduced to 40 percent when the cutback dropped control element assembly (CEA) regulating Groups 5 and 6, with steam being dumped to the main condenser through the steam bypass valves. Operators further reduced power to approximately 18 percent during boration and withdrawal of CEA Groups 5 and 6 to their proper position. Reactor power was maintained at approximately 18 percent on the steam bypass valves until the licensee's transformer group could ensure that no damage occurred to the A main transformer. Oil samples from the transformer were analyzed, and additional testing and inspection of the transformer were performed. The licensee returned the unit to the grid on September 5, after transformer testing was completed and the transient was analyzed by the licensee using their posttrip review process. The inspectors reviewed operator performance and the licensee's recovery actions and found them to be appropriate to the circumstances.

No violations or deviations were identified.

4. Monthly Maintenance Observation (62703)

The station maintenance activities affecting safety-related systems and components listed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with approved work authorizations (WAs), procedures, Technical Specifications, and appropriate industry codes or standards.

a. WA 01061984. On August 2, 1990, the inspector observed work being performed on MS 401B, one of the main steam supply valves to the turbine driven emergency feedwater pump (TDEFWP). The intermediate open limit switch had to be reset on the valve motor operator after it had been determined that the previous setting for the switch was not adequate to ensure proper operation of the valve. The valve was intended to first open partially (8 percent) when the pump received a start signal to prevent waterhammer in the steam piping and ensure that the pump did not overspeed as it started. It had been determined, during surveillance testing on July 28, that the valve did not open sufficiently to cause the turbine to roll until the valve received a full open signal.

The licensee had performed an engineering evaluation after the limit switch had been verified to be properly set. They determined that any binding of the valve, including packing, could prevent motor coastdown from getting the valve off the closed seat. Therefore, the 8 percent setting was inadequate to ensure that the valve would open. They further determined that a setting of 17 percent would ensure the valve would open sufficiently even without motor coastdown and would still meet the requirements to prevent waterhammer and overspeed.

WA 01061984 was modified to reset the limit switch and perform baseline motor operated valve analysis and test system (MOVATS) testing with the new setting. The inspector observed the setting of the limit switch. The manual operation of the valve for limit switch adjustment was being performed by maintenance personnel with the permission of operations. There was good coordination between operations and maintenance personnel because the TDEFWP had to be declared inoperable during the evolution by closing a downstream isolation valve. Pump unavailability was kept to a minimum. Once the limit switch was reset, additional problems were experienced with the valve when operations attempted to operate the valve electrically. When the valve was stroked shut from the control room, the valve operator DC supply breaker tripped on overload protection. When the MOVATS test leads were removed, the valve motor operated but it would not disengage the manual operator. The WA was again revised to remove the motor for inspection and it was found that the cams on the worm shaft assembly that operated the clutch tripper were damaged. The cams were replaced but the inspector was not able to witness the remainder of the maintenance due to subsequent problems with the MOVATS test leads.

The inspector learned on August 7 that additional problems were encountered with the valve the next day when MOVATS testing recommenced. It was finally determined after disassembly that the declutch fork in the valve motor operator had been installed backwards during past maintenance on the valve and continued to cause binding. This caused additional damage to the newly installed cams and caused the motor power supply to trip again. Once the problem was identified, the cams were replaced and the declutch fork was correctly installed. The valve was declared operable on August 4 after retesting. The TDEFWP continued to remain operable during this time, except during intermittent periods when MS-401B was being worked, because the redundant valve, MS-401A, was available to supply steam to the turbine.

The inspector reviewed the licensee's investigation and corrective action for the assembly error discovered during maintenance on MS-401B. The licensee determined that the improper installation of the declutch fork occurred during a routine overhaul of the valve motor operator in April 1988. The valve appeared to operate properly in the interim during periodic surveillance of the pump. The procedure used for Limitorque motor-operator maintenance, MM-6-105, Revision 2, was reviewed and the licensee interviewed the mechanic involved with the previous overhaul and determined that the procedure was clear on how to install the declutch fork. The licensee determined that earlier problems with operation of the declutch lever for MS-401B indicated the presence of a problem with the valve operator, but maintenance personnel did not identify the cause until the current problem arose. The licensee felt that the problem was not widespread due to the adequacy of their maintenance procedure and the training provided for the mechanics that work on motor-operated valves. Additionally, it was believed that MOVATS testing of AC motor-operated valves would reveal problems such as the binding caused by improper installation of the declutch fork. MS-401 A and -B were the only two safety-related DC motor-operated valves installed at Waterford 3.

Quality Notice QA-90-198 was written by the licensee on August 8 to document the procedural violation associated with the work on MS-401B. Corrective action by the licensee included the addition of a second party verification signoff in MM-6-105 for correct installation of the declutch fork. Even though the licensee contended that the fork was correctly installed in MS-401A, they verified it during the resetting of the limit switch on that valve on August 28, 1990. The inspector determined that the licensee's identification, investigation, and corrective actions for the above problem were adequate. No other problems were identified.

b. WA 01062000, 01062001. On August 14, 1990, the inspector observed preventive maintenance performed on the fan motors for the control room Train A air handling unit and the emergency filtration unit. Cleaning, megger testing, and inspection of the motors was being done in accordance with procedure ME-7-006, Revision 6, "480 VAC and Less Squirrel Cage Induction Motors." The inspector verified that the work was authorized to be performed by the shift supervisor and was being done in accordance with properly approved work instructions. The inspector determined that the electricians were familiar with the work to be performed and that the work instructions were adequate. Test equipment being used was properly calibrated.

c. WA 01061072. On August 15, 1990, the inspector observed maintenance performed in the shop on the spare chemical and volume control system (CVCS) letdown relief valve. The valve had been replaced on the CVCS letdown line earlier in the year, with a similar valve, due to a leak at the inlet flange. The valve was being refurbished in accordance with the technical manual and engineering input and the setpoint adjusted using procedure MM-7-001, Revision 4, "Safety and Relief Valve Bench Testing." The inspector verified that the work was done in accordance with a properly prepared and approved work instruction and that the instructions were adequate for the work being performed. The inspector observed work in progress including performance of "hold point" inspections by a QC inspector. Health physics requirements for the work were reviewed and determined to be appropriate and complied with by the workers involved.

d. WA 01062059. On August 21, 1990, the inspector observed work in progress on the fan for the B control room air handling unit, AH-12B. The work authorization called for the fan bearings to be lubricated, ar alignment check of the fan and motor, and a check of belt tightness. The alignment check and belt tightness were being done in accordance with MM-06-004, Revision 5, "Shaft Coupling Alignment and Belt Tensioning." The inspector verified that the work was being done in accordance with a properly prepared and approved work instruction and was appropriate for the work being performed.

e. WA 01063011. On August 28, 1990, the inspector observed work in progress on Valve MS 401A. MS 401A controls the steam supply from the A steam generator to the TDEFWP. The limit switch for the valve was being reset for the same reason as MS 401B discussed in paragraph 4.a above. In addition, the proper installation of the declutch fork was verified during the work. The inspector determined that the work was performed in accordance with a properly prepared work instruction and was authorized by the shift supervisor. Retest requirements included MOVATS testing of the valve and functional testing of the TDEFWP.

No violations or deviations were identified.

5. Monthly Surveillance Observation (61726)

The inspectors observed the surveillance testing of safety-related systems and components listed below to verify that the activities were being performed in accordance with the Technical Specifications (TS). The applicable procedures were reviewed for adequacy, test instrumentation was verified to be in calibration, and test data was reviewed for accuracy and completeness. The inspectors ascertained that any deficiencies identified were properly reviewed and resolved.

a. Procedure MI-03-0388, Revision 2, "Main Steam Line Radiation Monitor Channel Functional Test ARM-IR-5500 B." On August 2, 1990, the inspector observed the performance of the monthly functional test of the main steam line radiation monitor for the B steam generator to satisfy the surveillance requirements of TS 4.3.3.1, Table 4.3-3, Item 3.e. The inspector verified that the work was being performed in accordance with a properly approved procedure and was authorized by the shift supervisor. The surveillance was conducted in a controlled manner by qualified personnel. Although the test was being directed from the control room using the official copy of the procedure, actions had to be accomplished at two other locations in the plant because of remote equipment associated with the radiation monitor.

Section 4.4 of the procedure stated, "Each step performed in the procedure must be initialed and dated as it is completed." Certain steps were not initialed and dated until the test was completed and the instrumentaiton and control (I&C) technicians who were at the remote locations returned to the control room. The lead technician who was directing the test was in communication with the other personnel during the test. He verified that all of the steps were completed as required as he progressed through the test. In addition, the technicians at the location where any significant actions had to take place had another copy of the procedure to follow.

This matter was discussed with the I&C assistant maintenance superintendent. It was concluded that additional guidance was needed for proper signoff of activities where actions are required to take place at remote locations. The licensee informed the inspector that uniform written guidance would be issued for the entire maintenance department describing how evolutions involving simultaneous work at more that one location would be handled to ensure proper procedure completion and signoff. The inspector will review this guidance when it is issued (Inspector Followup Item 382/9019-02).

b. Procedure MI-03-504, Revision 2, "Broad Range Gas Detection System Channel Functional Test and Calibration HVC-IA-5510 B." On August 21, 1990, the inspector observed the performance of the monthly functional test of the B broad range gas monitor being performed to satisfy the surveillance requirements of TS 4.3.3.7.3. The inspector verified that the work was being performed in accordance with a properly approved procedure and that it was authorized by the shift supervisor. The surveillance was conducted in a controlled manner by qualified personnel. Test equipment being used was properly calibrated. The inspector noted that the output voltages being measured in accordance with Steps 8.3.7, 8.3.9, and 8.3.77 were not within the required tolerance specified on the calibration record form, but the technician entered an explanatory note. The inspector questioned the I&C supervisor about this fact and determined that the voltages could not be adjusted to within tolerance because of a component problem in the circuitry of the instrument. This problem had been previously identified, and a design change (DC-3193) was being processed to correct the problem. The output voltage was used to drive only the recorder associated with the instrument, and the I&C supervisor explained that the recorder did not have to work properly for the monitor to perform its safety function of control room isolation. The inspector found this approach to be acceptable until the design change was implemented.

c. Procedure PE-05-033, Revision 4, "NPIS Common Foundation Basemat Integrity Check," Section 8.2, "Crack Width Monitoring." On August 29, 1990, the inspector observed a portion of the performance of PE-05-033, Section 8.2. The surveillance was being performed to satisfy, in part, the requirements of TS 6.8.4.e, "Basemat Monitoring." The inspector verified that the surveillance was performed in accordance with a properly approved procedure using calibrated measuring equipment.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation, to assure that selected activities of the licensee's radiological protection programs were implemented in conformance with plant policies and procedures and in compliance with regulatory requirements, and to inspect the licensee's compliance with the approved physical security plan.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. Through in-plant observations and attendance of the licensee's plan-of-the-day meetings, the inspectors maintained cognizance over plant status and TS action statements in effect.

On August 9, 1990, at approximately 12:45 p.m., the inspector observed a final access control security officer allowing two NRC visitors access to the protected area from the primary access point, when those visitors were not authorized for unescorted access. The licensee's failure to comply with Section 5.2.3.2 of the licensee's Plant Security Procedure PS-015-107, Revision 8, "Duties of Personnel at the Primary Access Point," is a violation of TS 6.8.1.d which, in part, requires such procedures to be implemented. The inspector, who was the designated escort, was processing himself and another visitor when the two visitors were admitted. Upon observing the violation, the inspector promptly entered the protected area and took control of the visitors. He also informed the security officer of the violation, who explained he was misled by the NRC identification badge worn by the second visitor who was permitted to enter in error. Upon following up with licensee security management, the inspector found that no action was taken to identify, document, or correct the violation. Subsequently the inspector was informed that an investigation was conducted.

Although the visitors remained in plain sight of both the escort and the security officer, the licensee's procedure requiring escorts to enter the protected area before the visitors are admitted was not followed. The licensee then took prompt corrective action by logging the event in the safeguards event log, initiating a quality notice and a security incident report to enter the event into the licensee's corrective action programs, retraining the individual security officer, and issuing a training bulletin to be signed by the other security officers. Disciplinary action was taken against the individual and his supervisor, principally for failure to identify the violation when it occurred. In view of the fact that the visitors were always in plain sight of the designated escort and the security officer and that the visitors were NRC personnel with a valid NRC security clearance, this event was of minimal safety significance. Thus a Severity Level V has been assigned. Based on the licensee's prompt and thorough corrective action, a Notice of Violation is not being issued as permitted by 10 CFR 2, Appendix C, Section V.A., "Enforcement Actions."

The resident inspectors continue to monitor pressurizer code safety-relief valve leakage which has increased slightly during this reporting period. Identified reactor coolant system leakage (to the appropriate tanks) has increased to approximately .7 gpm and the operators continue to have to vent and cool the quench tank to maintain its parameters within normal limits. As reported previously, the plant is being operated at reduced pressure to minimize the leakage. The licensee continued to make contingency plans to shutdown and repair the leaking valves, if it becomes necessary, prior to the next scheduled outage.

7. Followup of Previously Identified Items (92701, 92702)

a. (Closed) Violation 382/8917-06: The Notice of Violation cited three examples of where the licensee failed to adequately establish and maintain procedures as required by TS 6.8.1.a. The specifics of Examples 1 and 2 involved operating and annunciator response procedures not reflecting proper controls over the emergency diesel generator (EDG) duplex strainer selector valves as required by the EDG technical manual. The inspector noted it took three attempts to amend the EDG standby system valve lineup over a period of 5 months, and the last change (Change 8) to Operating Procedure OP-9-002, Revision 10, "Emergency Diesel Generator," still contained editorial errors. The editorial errors had no safety significance; however, it reflected inattention to detail during the review process. This was discussed with the licensee. Example 3 involved failure to reflect a design drawing revision which changed the required standby position for two component cooling water (CCW) system valves. The procedure was corrected, and other corrective actions as to root cause were described in LER 382/89-006, which was closed in NRC Inspection Report 50-382/90-15. This violation is closed.

b. (Closed) Violation 382/8917-07: This violation involved failure of the plant operations review committee to review a change to the CCW system. The system was changed to a different standby valve configuration to accommodate a piping class change. The cause appeared to be isolated to an administrative procedure inadequacy, which was corrected on June 1, 1989. The deficiency was related to Example 3 of the above closed violation, 382/8917-06. This issue was also addressed in LER 382/89-006. This violation is closed.

c. (Closed) Inspector Followup Item 382/8922-02: This item was opened to followup on the licensee's analysis and investigation of a charging pump failure in July 1989. The actual failure was caused when a crosshead bearing ball, attached to one of the B charging pump connecting rods, fractured and caused the connecting rod to jam and trip the pump. During the repair of the pump, it was also discovered that the block of the pump was cracked. The licensee contacted the pump manufacturer and determined that, although not a common problem, the failure of the bearing ball had occurred on other similar pumps. The licensee concluded that the failure was due to fatigue. It was also concluded that the failure was not reportable under 10 CFR 21. The failed bearing ball was replaced along with other damaged parts, and the others in that pump were inspected. The licensee established repetitive tasks to dye penetrant test the bearing balls in all the charging pumps periodically to detect indications of potential failures before the failures occur.

During the repair of the B charging pump, it was discovered that the block of the pump had developed a crack in the inboard cylinder plunger bore. The licensee determined that this was a recurring problem at other Combustion Engineering plants with similar charging pumps and that the Combustion Engineering owners group had a task group to address the problem. It was concluded, after an evaluation by the licensee, that the pump could remain in service with the cracked block and be considered operable but that the block should be replaced with a block of an improved design when one could be obtained. To date, the licensee has replaced the blocks on the A and B charging pumps with blocks which should be less susceptible to cracking. The AB pump was caution tagged to alert the operators to minimize its use until another new block can be obtained for it. The licensee scheduled the replacement of the AB charging pump block during the next refueling outage. The inspector considered the licensee's actions related to the July 1989 failure of the B charging pump adequate. This item is closed.

d. (Closed) Unresolved Item 382/9009-02: During a containment isolation system walkdown, the inspectors identified a concern over the conditions under which the steam generator blowdown containment isolation valves were in-service tested. The licensee's surveillance procedure required testing valve stroke time with no flow, when normally a flow condition would exist if the valve was called upon to isolate. The acceptance criterion in the surveillance test procedure did not account for the no-flow condition. The licensee researched the issue and presented the inspectors with Ebasco Services Incorporated Specification No. LOU-1564.104 and the valve purchase order which specified that the valves supplied shall have actuators sized to produce smooth operation from 0 to 100 percent stroke in less than the 10-second TS limit, with a differential pressure equal to valve design pressure. The certificates of compliance indicated that the valves were supplied in accordance with the above purchase specifications. The licensee did not (normally they would not) have the valve vendor's calculations and design data so that calculations could be performed to establish a no-flow acceptance criterion that would assure compliance with the TS limit of 10 seconds with full flow. However, as of the end of this inspection period, the licensee indicated that vendor test data was being made available. Experience with the feedwater stop valves indicated that stroke time may increase by only about 20 percent when considering flow and, since the slowest of the blowdown valves have been closing in 4 seconds or less, a 20 percent increase in time would still only be half of the limit of 10 seconds. A 50 percent increase in time, i.e., 6 seconds, would require corrective action in accordance with the surveillance procedure, so there appeared to be sufficient margin to account for full flow conditions. The licensee currently has a task in engineering (Problem Evaluation/Information Request No. 86012) to evaluate if the 10-second limit is valid under no-flow conditions or to provide a new time limit which will ensure 10 second closure under design flow conditions. The inspectors will follow up to verify completion of the task (Inspector Followup Item 382/9019-03). This Unresolved Item is closed.

No violations or deviations were identified.

8. Licensee Event Report (LER) Followup (90712)

The following LERs were reviewed and closed. The inspectors verified that reporting requirements had been met, causes had been identified, corrective actions appeared appropriate, generic applicability had been considered, and the LER forms were complete. The inspectors confirmed that unreviewed safety questions and violations of TS, license conditions, or other regulatory requirements had been adequately described.

a. (Closed) LER 382/90-007, "Incorrect Local Leak Rate Test Results Due to an Inadequate Procedure."

   This event resulted in the issuance of a Notice of Violation (382/9014-01). The licensee's corrective action to prevent recurrence will be reviewed during closeout of the violation response. This LER is closed.

b. (Closed) LER 382/90-008, "Loss of Essential Service Trains During Plant Operation."

c. (Closed) LER 382/90-010, "Inconsistencies in the Pump and Valve In-Service Test Program."

No violations or deviations were identified

9. Fire Protection Program Followup (92701)

The objective of this inspection was to follow up on the licensee's progress on fire barrier penetration seals and other selected items discussed in NRC Inspection Report 50-382/88-29. Early in 1988, the licensee's surveillance test program identified significant problems with fire barrier penetrations. In November 1988, the licensee initiated a major program to ensure the integrity of all fire barrier seals and provide programmatic changes to prevent a recurrence of the problem.

The inspector reviewed Procedure ME-3-006, Revision 3, "Surveillance Procedure Fire Barrier Penetration Seals," dated April 12, 1988. It was noted during this review that Change 2, issued on November 21, 1988, deleted the acceptance of the 10 percent damage criteria. This criteria would have allowed inoperable seals to be passed since the installed seal dimensions matched the approved configuration fire test. This was a significant program improvement.

Russkin fire dampers used in ventilation ducts have been a continuing problem in the industry. The ability of these dampers to close under normal air flow has been questionable. The licensee has elected to secure ventilation flow in case of a fire to assure closure. This action was included in the pre-fire strategies and, therefore, accounted for the specific dampers of interest. The fire brigade leader was alerted by a "Note" in the pre-fire strategy and requested the control room to take the necessary action to secure the specified ventilation flow. This was in accordance with the licensee's procedure policy.

The inspector also reviewed LERs 382/88-025 and -030, Engineering Evaluation CFR21-90-008, and Supplemental Safety Evaluation Reports (SSERs) 3, 5, 8, and 10. This review was to evaluate the licensee's action on other fire barrier problems.

LER 382/88-025 was generated as a result of a potentially reportable event (PRE) form submittal (PRE 88-098) and identified the failure to include certain 1-hour barriers in the surveillance test. This failure was attributed to personnel and procedural error. The PRE also identified the failure to install a required 1-hour barrier around a ventilation duct. This LER resulted in an extensive inspection by the licensee. A design change (DC-3134) has been issued to install the missing barrier.

During the review of LER 382/88-030 (including Revisions 1 and 2), the inspector noted that major voids were found in April 1989 while the licensee was conducting the 100 percent fire penetration seal inspection. These voids were in the Promotec seals and were found when the permanent damming boards were removed. In the original version of the LER, the licensee acknowledged that the 10 CFR 21 report concerning installation errors discovered with Promotec seals was received and evaluated in October 1987.

Engineering Evaluation CFR21-90-008, dated July 5, 1990, concerned the Tremco joint seals installed in the expansion joint at the containment wall. This joint was described in Section 9.5 of the Waterford 3 final safety analysis report (FSAR). It was identified as a fire barrier seal in early 1989. The problem was reported in LER 382/88-030, Revision 2, in July 1989. A design change (DC-3197) had been issued to replace the seals. The licensee was in the process of evaluating this issue for reportability under 10 CFR 21.

During the review of the SSERs above, the inspector noted three items, two affecting fire barriers and one affecting equipment certification. Licensee Letter W3P84-1418 requested a deviation from having a tested seal installed in the wall-to-ceiling gap on certain barriers. The deviation was approved in SSER 8. Subsequently, the licensee identified that the constructor had unilaterally authorized the deletion of the gap seal material. Upon discovery, fire impairment notices were issued and fire watches established where required. The licensee issued WAs to repair the gap seals. This item was also discussed in NRC Inspection Report 50-382/88-29.

The second item affecting fire barriers was the lack of a 1 1/2-hour damper which was required to be installed in the east wall (8B) of the cable spreading room. The FSAR indicated that this was an approved deviation. SSER 8 does not identify this specific damper; however, the licensee's original letter (W3P84-0709) dated March 26, 1984, addresses the specific damper. The FSAR stated that detection and suppression existed on both sides of the wall when, in fact, it was installed on one side only. This discrepancy had been identified by the licensee, and a licensing document change request had been submitted.

SSER 5 approved a "temporary lack of Factory Mutual (FM) approval" for the fire detection equipment supplied to the licensee by Alison Controls, Inc. (ACI). The licensee has been unable to obtain FM approval as of the time of this inspection. The ACI equipment that was installed at this site has been discontinued by ACI. As a result, repair and replacement parts were no longer available. The licensee had been pursuing replacement of the entire system with equipment that would be FM approved.

The inspector reviewed Problem Evaluation/Information Request (PEIR) 10852, dated March 1, 1990. This document reported that replacement wire for the installed thermistor heat detection sensor wire was no longer available. The response to the PEIR identified a replacement part and stipulated that it would provide exactly the same operational characteristics as the original wire. The inspector reviewed the vendor information on the wire and found it in support of the response. The only significant difference was the connectors used on the terminations, which had no impact on the operation of the wire.

NRC Inspection Report 50-382/88-29 discussed the review of a modification to the reactor coolant pump oil collection system. This report found the redesigned collection system to be in compliance with the criteria of 10 CFR 50, Appendix R. Subsequently, the licensee added remote fill lines to both the upper and lower oil reservoirs on the reactor coolant pumps. The inspector reviewed the safety evaluation and associated fire hazards analysis. Based on the assumptions and criteria used, and since the fill lines would not normally contain oil except during filling, the inspector found the modifications acceptable.

Overall, the inspector noted that progress in completion of the correction of deficiencies appeared to be slow. However, in view of the large scope of this effort, the inaccessibility of many of the fire barriers while operating the plant, and the compensation actions (fire watches) taken by the licensee, there was no safety concern.

No violations or deviations were identified.

10. Exit Interview (30703)

The inspection scope and findings were summarized on September 5, 1990, with those persons indicated in paragraph 1 above. The licensee acknowledged the inspectors' findings. The licensee did not identify as proprietary any of the material provided to, or reviewed by, the inspectors during this inspection.