APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report No: 50-382/92-03

Docket No: 50-382 License No: NPF-38

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: February 2 through March 14, 1992

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

I. Barnes, Chief, Materials and Quality Programs Section,
Division of Reactor Safety

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

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

D. R. Hunter, Reactor Inspector, Operational Programs Section,
Division of Reactor Safety

Approved: Mark A Satorius for William D. Johnson, Chief, Project Section A   3/30/92 Date

Inspection Summary

Inspection Conducted February 2 through March 14, 1992 (Report 50-382/92-03)

Areas Inspected: Routine, unannounced inspection of plant status, followup, onsite response to events, monthly maintenance observation, bimonthly surveillance observation, operational safety verification, and reliable decay heat removal during outages.

Results:

The inspector concluded that the licensee's actions on the thermo-lag issue were proactive and appropriate. The licensee has expended considerable resources and has made good progress in a long-term effort to resolve all fire

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barrier issues identified in the past 4 years, and appeared to be approaching completion in the near future (paragraph 3.2.1). A violation was identified in paragraph 3.3.2 involving failure to provide a complete and accurate licensee event report (LER) on the COLSS margin alarm issue. This was a third example in the past year where required information was not provided in an LER, which may be indicative of weaknesses in both LER writing and technical reviews. The overall format and content of recent LERs have been good, with exception of these specific inaccuracies (paragraph 3.3).

The licensee's performance in dealing with the safety injection tank (SIT) pressure problem in paragraph 3.4.2 was a strength. Therefore, a violation was not cited. The licensee's actions to prevent recurrence of the Struthers Dunn 600 series relay failing were adequate in that the failure appeared to be an isolated case. Both LERs were well written (paragraph 3.4).

Based on a review of past installation and retesting practice used on steam generator (SG) primary manways, the inspectors identified a violation involving failure to follow written instructions (paragraph 4.1).

Weaknesses were identified in the licensee's procurement process in that inadequate controls were placed on the procurement of commercial equipment that could have an effect on important balance-of-plant or safety-related equipment.

The licensee's actions to repair the leaking SG manway were excellent. An unresolved item was initiated to permit further review as to whether or not the previous installation of helicoils was in violation of NRC regulations; however, they were installed using a sound technical basis.

The licensee's nonlicensed auxiliary operator (NAO) exhibited excellence in the performance of his routine inspection tour by finding the Emergency Diesel Generator (EDG) A control air supply valves out of position (paragraph 4.3); however, a second unresolved item was initiated to allow the licensee to determine whether or not EDG A was operable during the period the valves were out of position (paragraph 4).

Overall performance of maintenance activities observed during this inspection period was excellent. Work was accomplished in a timely and professional manner. A minor weakness was noted in the planning and procedures aspect of the work observed, including errors in the hot gas bypass modification on Essential Chiller B, causing it to fail the acceptance test (paragraph 5).

Surveillance testing continued to be a strength at Waterford 3. A minor weakness was identified during fuel handling building (FHB) ventilation system testing in that the test director, who was a system engineer, failed to sign off completed steps as they were done. This was a poor practice (paragraph 6).

The licensee's performance in executing the planned outage was excellent. Close management involvement, maintenance of appropriate priorities, and a high sense of concern and vigilance over operations during reduced reactor coolant system (RCS) inventory all contributed to the orderly completion and success of the outage. However, the inspectors identified a weakness in the licensee's handling of SI-405A and -B pressure switch drift. Only after the inspectors intervened did the licensee take action to ensure there was sufficient margin to ensure the valves would open if called upon.

Housekeeping during and after the outage was a strength. The inspectors noted a distinct improvement in this area over this inspection period (paragraph 7).

DETAILS

1. PERSONS CONTACTED

1.1 Principal Licensee Employees

*D. F. Packer, General Manager, Plant Operations
*T. R. Leonard, Technical Services Manager
R. S. Starkey, Operations and Maintenance Manager
R. E. Allen, Security and General Support Manager
*J. J. Zabritski, Quality Assurance Manager (Acting)
*D. E. Baker, Director, Operations Support and Assessments
*J. B. Houghtaling, Director, Design Engineering (Acting)
J. A. Ridgel, Radiation Protection Superintendent
*G. M. Davis, Events Analysis Reporting & Response Manager
*R. F. Burski, Director, Nuclear Safety
*L. W. Laughlin, Licensing Manager
T. J. Gaudet, Operational Licensing Supervisor
*J. G. Hoffpauir, Maintenance Superintendent
D. W. Vinci, Operations Superintendent
R. D. Peters, Assistant Maintenance Superintendent, Electrical
D. E. Marpe, Assistant Maintenance Superintendent, Mechanical
D. C. Matheny, Assistant Maintenance Superintendent, Instrumentation and Controls
A. L. Holder, Supervisor, Fire Protection & Safety
O. P. Pipkins, Licensing Support
L. R. LeBlanc, Licensing Support Supervisor
*T. B. Brennan, Design Engineering Manager
*R. W. Prados, Senior Engineer, Licensing
*G. G. Davie, OAID Manager

*Present at exit interview.

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)

The plant was operated at full power until February 16, 1992, when the plant was shut down for a 10-day planned outage to replace the primary manway gaskets on both SGs (see paragraph 4.1). The plant was cooled down and depressurized and the RCS was partially drained to accommodate the work. During the outage, several other work items were accomplished (see paragraphs 5. and 7.). On February 23, plant heatup commenced and, by February 26, the plant was again operating at full power where it remained until the end of this inspection period.

3. FOLLOWUP

3.1 Followup of Previous Inspection Findings (92701, 92702)

3.1.1 (Closed) Inspection Followup Item (IFI) 90022-1

This item was opened to follow up on the licensee's investigation and corrective action for a September 19, 1990, transient caused by loss of extraction steam to the high pressure feedwater heaters. The inspector reviewed Significant Occurrence Report 90-023, which was completed and approved by the plant manager on August 5, 1991. The report concluded that the transient was caused by valve mislabeling on the high pressure feedwater heaters, which led an operator to close an isolation valve for the level switch, which closed the extraction steam Isolation Valve ES-109 on an indicated high heater level. The operator had intended to isolate and tag a level controller on the heater for maintenance. Corrective action included correcting the identified labeling error and requesting the Operations Quality Assurance Group to perform a surveillance of component labeling on the condensate, feedwater and the feedwater heater drain systems to determine the extent of the problem. Surveillance QS-90-032 was completed January 16, 1991, and of the 133 randomly selected components one was mislabeled. The Operations department had already developed and implemented a component tag and labeling enhancement program which was projected to take approximately 3 years to complete. They indicated that this program should aid in identifying and correcting other component labeling problems. This item is closed.

3.1.2 (Closed) Inspection Followup Item IFI 90024-2

This item was opened to follow up on the licensee's corrective action for deficiencies identified with fuses and fuse holders in the power supplies for their Westinghouse 7300 Process Analog Control (PAC) cabinets. Several fuse and/or fuseholder failures had caused minor plant transients and temporary loss of some indication. The inspector reviewed the licensee's "Fuse and Fuse Holder Failure Report" dated December 6, 1990, and their root cause investigation report, RCI 90-021, dated March 22, 1991. The licensee had done an excellent job of investigating the cause of the fuse and fuseholder failures and establishing corrective actions to prevent recurrence. They had determined that the 20-ampere rated fuse holders were not sufficient to supply the required power to some of the PAC card racks. Specifically, some of the triple-frame card racks drew as much as 17.8 amperes under normal conditions and would overheat and degrade the fuseholders over time and, in some cases, cause the fuses to fail even though current through them was less than the 20-ampere rating. With the concurrence of Westinghouse, the licensee replaced the power supply fuse holders in cabinets with triple-frame card racks with 30-ampere rated holders and used soldered connections to further reduce the resistance, which caused heating and degradation. The system engineer indicated that he periodically monitored the PAC cabinets with a thermographic camera and did not see any further signs of overheating in the fuse holders. He also indicated that a design change to supply forced ventilation to the cabinets was pending and, even though it was intended to prolong the life of the PAC cards, it should further reduce the heat load on the power supply fuse holders. It was found during the investigation that some of the power supply fuse holders had 15-ampere fuses installed instead of the 20-ampere fuses specified on the vendor drawings. The licensee has established a program for control of electrical fuses at Waterford 3, which should prevent incorrect fuses from being installed in the future. This item is closed.

3.1.3 (Closed) Violation VIO 90026-5

This violation was cited under Enforcement Action 91-006 dated March 15, 1991, as a two-part, Severity Level III problem. The issues involved the licensee's conclusion in late December 1990, that problems associated with work control, surveillance testing, and operation of the control room air conditioning system had placed into question the integrity of the control room envelope and, therefore, the protection afforded control room operators from events such as radiation releases and toxic gas emergencies. The licensee responded to the Notice of Violation on April 15, 1990, and committed to the corrective actions discussed below. The objective of this followup inspection was to verify satisfactory completion of the corrective actions.

Repairs to leakage paths in the control room were completed by December 21, 1990, such that subsequent testing results achieved at least 0.125 inches water gauge positive pressure in the control room, with less than 200 cubic feet per minute makeup air. The inspectors reviewed the test results and found no problems. Surveillance Procedure PE-5-004, Revision 5, "Control Room Air Conditioning Surveillance," was changed to include the 200 cubic feet per minute makeup air flowrate limit as an explicit acceptance criterion, and detailed guidance was provided when any of the acceptance criteria could not be met. On March 4, 1992, the inspectors reviewed Revision 6 and noted that the changes were incorporated, with improved format, in the new revision.

Under long-term, permanent corrective actions, the licensee's Maintenance Review Committee audited the condition identification (CI) report database to ensure that CIs open for more than 3 months were adequately addressed. The inspector noted documentation stating that the results were satisfactory. Also, PE-5-004 was evaluated and revised appropriately to ensure that interfacing ventilation systems were always in the same condition while testing the control room air conditioning system and that measured makeup air flowrates were normalized to 0.125 IWG pressure in the control room to permit meaningful precursor trending. The inspector noted that the new Revision 6 retained those attributes.

On June 14, 1991, the licensee developed a case study on this event so that it could be discussed on a recurring basis with their technical staff. The inspector noted that Training Request No. 91094 was implemented to accomplish this and was scheduled to be covered as part of continuing training beginning December 1991.

The licensee performed an evaluation of procedures used for design change development. The inspector noted that two procedures were changed accordingly on February 28, 1992. The inspector reviewed a sampling of nine Design Document Revision Notices, which showed objective evidence that the licensee revised the nuclear penetration list to identify air pressure seals within the control room envelope or the controlled ventilation area section (CVAS) in the reactor auxiliary building. On February 27, 1992, the licensee completed an evaluation of the feasibility of labeling seals that affect pressure envelopes controlled by Technical Specifications (TS). Based upon changes made to procedures, and a new "Barrier Functional List" created to work in conjunction with the Nuclear Penetration List, the licensee considered field labeling of nuclear penetrations related to air boundaries was not warranted. The inspector had no problem with that decision since other controls had been implemented as discussed above.

Finally, the inspector reviewed the licensee's actions to revise Design Change No. 3197 to address the fire seals that affected the integrity of the control room, CVAS, FHB, and shield building boundaries. The inspector noted that appropriate changes were made to address the control room and CVAS boundaries, but none were made to address the FHB and shield building because nothing in the scope of the design change package impacted FHB and shield building boundaries. This violation is closed.

3.1.4 (Closed) Violation VIO 91013-1

This violation involved four examples of a failure to properly implement procedures required by TS 6.8.1. The first example involved a failure of Refueling Procedure RF-006-001, Revision 3, "Reactor Vessel Head and Internals Installation," to properly control refueling cavity water level to prevent high radiation during the lift of the upper guide structure from causing unnecessary radiation exposure to personnel and an unnecessary actuation of containment purge isolation. As corrective action, the licensee made revisions to RF-006-001, RF-004-001, "Reactor Vessel Head and Internals Removal," and RF-004-002, "Incore Instrumentation Removal and Disposal," to give adequate guidance on controlling refueling cavity water level during high exposure lifts to minimize radiation exposure to personnel and on precautions to ensure that the containment purge system was shut down to prevent an unnecessary challenge to that safety system. The inspector noted that the changes to the above procedures were made before the committed date and found them to be satisfactory.

The next example involved a failure to respond to an alarm that was intended to alert the operators to a failure of the Safety Parameter Display System (SPDS). As a result, the SPDS was not functioning for over 24 hours, which diminished the licensee's ability to make offsite dose assessments during an accident. This was reportable to the NRC under 10 CFR Part 50.72. The licensee's corrective action included a letter to all licensed operators to heighten their awareness of the importance of this alarm and review their responsibilities to acknowledge alarms as required by Procedure OP-100-001, "Duties and Responsibilities of Operators on Duty." They also indicated that their computer group would investigate ways of enhancing the alarm indication for a nonfunctioning SPDS to ensure it would get the attention of the operators in the control room. The letter to licensed operators was issued by the committed date and was found to be satisfactory upon review by the inspectors.

Another example of the violation involved a failure to properly perform an independent verification during motor-operated valve analysis and test system (MOVATS) testing of Valve BAM-113A. Because the valve was located inside a contaminated area, the workers were not able to follow the strict guidance in Procedure UNT-005-010, Revision 2, "Independent Verification Program," and obtain verification and signatures before they proceeded beyond the applicable steps. The licensee's corrective action included changing Procedure UNT-005-010 to provide some flexibility to workers as allowed by their upper tier document, Site Directive W2.101, "Procedure Compliance." This guidance allowed the use of communications between a verifier and a procedure reader when working conditions prohibited direct procedural usage. The change to Procedure UNT-005-010 was made by the committed date and was found to be satisfactory.

The final example of procedural noncompliance involved a mispositioning of Valves EGF-123A and -124A which caused a test run of EDG A to be aborted due to an overflow of fuel oil. Since the licensee was unable to identify the circumstances which led to the valves being mispositioned, they immediately increased administrative controls by changing the standby valve lineup of Procedure OP-009-002, Revision 11, "Emergency Diesel Generator," to require EGF-123A(B) and -124A(B) to be locked open. Since it was known that the valves were sometimes operated when filling the fuel oil storage tanks, this was proceduralized in Procedure OP-003-009, "Fuel Oil Receipt," to prevent the inadvertent mispositioning of the valves. The change to Procedure OP-003-002 was made as committed and also found to be satisfactory. The inspectors will continue to monitor the licensee's procedural compliance during routine inspections. This violation is closed.

3.1.5 (Closed) Violation VIO 91021-1

The violation cited three examples of the licensee's failure to meet the requirements of 10 CFR Part 50, Appendix B, for corrective action, and their Corrective Action Program as described in Site Directive W2.501. The inspector reviewed their response to the Notice of Violation dated September 17, 1991, and the indicated corrective action which included issuance of Quality Notices for the three cited conditions adverse to quality and training for maintenance and maintenance engineering personnel. The training consisted of a memorandum from the Maintenance Superintendent covering the violation and the requirements of the licensee's Corrective Action Program and his expectations for maintenance personnel to identify and document conditions adverse to quality. The content of the memorandum was covered with maintenance engineering and electrical, mechanical, and instrumentation and control maintenance personnel in shop meetings by the committed date as demonstrated by meeting rosters. The inspector considered the corrective action adequate for the violation and properly implemented in accordance with the licensee's commitment. This violation is closed.

3.1.6 (Closed) Violation VIO 91021-3

This violation was cited for a failure to comply with TS 3.8.1.1 action requirements for an inoperable EDG to ensure the operability of offsite A.C.

power sources by verifying correct breaker alignment within 1 hour. The inspector reviewed the licensee's response dated September 17, 1991, and their stated corrective action which included the issuance of a new procedure, OP-100-014, Revision 0, "Technical Specification Compliance," which was intended to standardize and provide procedural guidance for TS compliance, particularly for inoperable EDGs resulting from inoperable support systems. In addition, precautions and guidance were added to the operating procedures for "Component Cooling Water," Procedure OP-002-003, and "Chilled Water," Procedure OP-002-004, which alerted the operators to use the guidance in OP-100-014 when a train of the system became inoperable. The inspector reviewed the procedure and procedure changes and considered the corrective action appropriate and adequate to prevent recurrence. This violation is closed.

3.2 Other Followup (92701)

3.2.1 Fire Protection Program Followup

The objective of this inspection followup was to review the licensee's actions as a result of NRC Information Notices 91-47, "Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test," and 91-79, "Deficiencies in the Procedures for Installing Thermo-Lag Fire Barrier Materials." These information notices alerted licensees to problems that could result from the improper use or installation of thermo-lag material to satisfy fire protection requirements for safe shutdown components specified in 10 CFR Part 50, Appendix R.

The use of thermo-lag material by the licensee at Waterford 3 was very limited. Thermo-lag was used to construct two barriers located on the +46 foot elevation of the reactor auxiliary building in the heating and ventilation room. One of these barriers was a 1-hour fire wall separating Essential Chiller AB from Essential Chillers A and B. The other barrier was a 1-hour fire wall separating Air Handling Units 13A and 13B. Both fire walls were only partitions and did not separate their respective components into separate rooms. The licensee requested, and was granted, an exemption by the NRC for this configuration. A third barrier was constructed with thermo-lag panels on the +35-foot elevation of the reactor auxiliary building adjacent to the reactor containment building in the Train A electrical penetration area. This barrier enclosed Containment Electrical Penetration No. 107.

Thermo-lag was also used to provide 1-hour barriers for fire damper installations where the damper assembly was installed external to the fire rated barrier penetrated by the ventilation duct.

All thermo-lag installations had been declared inoperable by the licensee and the required compensatory measures implemented. This action was initiated by the performance of the fire barrier inspection surveillance test in late 1988. The conditions discovered were reported in LER 88-025. Design Change No. 3134 was issued and subsequently revised to correct the identified deficiencies. The inspector was informed by the licensee that partitions in the heating and ventilation rooms and some of the fire damper barriers would be replaced with different barrier material. The disposition of the remaining thermo-lag applications was pending further review of the use of thermo-lag.

Conclusions:

The inspector concluded that the licensee's actions on the thermo-lag issue were proactive and appropriate. The licensee has expended considerable resources and has made good progress in a long-term effort to resolve all fire barrier issues identified in the past 4 years and appeared to be approaching completion in the near future.

3.3 In-Office Review of LERs (90712)

The following LERs were reviewed. The inspectors verified that reporting requirements had been met. causes had been identified, corrective actions appeared appropriate, generic applicability had been considered, and that 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. The Region IV staff determined that an onsite inspection followup of the event was not appropriate. The NRC tracking status is indicated below.

3.3.1 (Closed) LER 91-022, "Inadvertent Engineered Safety Features Actuations due to Plant Protection System Test Circuit Malfunction"

The inspector reviewed the LER and found that it was complete, accurate, and timely. Prior to the event, the licensee was actively pursuing improvements to the plant protection system test circuitry due to previous malfunctions and indicated that the corrective action for the latest malfunction would be included in a design change that was currently planned to be implemented during the next refueling outage. The corrective actions were considered appropriate to prevent recurrence of the failure. This LER is closed.

3.3.2 (Open) LER 92-001, "Failure to Satisfy Technical Specification Surveillance Requirement due to Inadequate Administrative Controls and Inadequate Attention to Detail"

On February 26, 1992, the inspector reviewed this LER for accuracy and completeness, in addition to the above attributes. This issue was addressed in NRC Inspection Report 50-382/91-31, paragraph 4.2. The licensee found the azimuthal power tilt alarm not properly set and determined, upon investigating the causes, that Surveillance Procedure NE-5-103, Revision 3, "COLSS Alarm Verification," did not properly meet the stated requirements of TS 4.2.3.2.a. The procedure verified that the COLSS alarm was functional, but failed to verify the correct setpoint. A violation was not cited for failure to meet TS surveillance requirements because the error had minor safety significance and the licensee's corrective actions appeared to address all of the concerns. During a separate surveillance program inspection conducted by Region IV on February 4-7, the regional inspector identified a similar problem with the COLSS margin alarm associated with the core power operating limit based on peak linear heat generation rate (PLHGR) in kilowatts per foot (TS 4.2.1.3). When the regional inspector identified the problem, the licensee informed him that the problem was being addressed along with the azimuthal tilt alarm problem. The Region IV inspector documented this in NRC Inspection Report 50-382/92-04, paragraph 3, and stated that NRC would follow up. When the licensee completed their review, they found that a similar problem existed for the Departure from Nucleate Boiling Ratio (DNBR) margin alarm (TS 4.2.4.3). The procedure for all three alarm surveillances was revised, and software changes were implemented in order to meet the TS surveillance requirements. There was no concern about the alarm setpoint for the DNBR and PLHGR margin alarms because the COLSS continuously calculated the margins. With azimuthal tilt, however, a fixed addressable constant was set into both the COLSS and the core protection calculator (CPC), and it was subject to adjustment by the operators during power operation.

The LER focused on the azimuthal tilt problem and failed to address the problems found with the DNBR and PLHGR margin alarms. On Page 7 it stated "No other COLSS-CPC related procedures exist which could have a similar error." The inspector discussed this with the licensee, who explained there was a communications breakdown between personnel who performed the corrective actions and those responsible for properly reporting the issue pursuant to 10 CFR Part 50.73. This was also indicative of a weakness in the review and approval process of the LER. The licensee stated that the LER would be revised. Over the past year, the resident inspectors identified two other cases where an LER failed to accurately and fully report an event, resulting in revisions (see LERs 91-008 and 91-011). Failure to identify the DNBR and PLHGR margin alarm surveillance problems is a violation of 10 CFR Part 50.73(b) in that information provided to the NRC by the licensee did not include a complete and accurate description of the event and actions taken to prevent a recurrence (VIO 92003-1).

This LER shall remain open until an acceptable revision is issued and satisfactorily reviewed.

Conclusions:

A violation was identified in paragraph 3.3.2 above involving failure to provide a complete and accurate LER on the COLSS margin alarm issue. This was a third recent example where required information was not provided in an LER, which may be indicative of weaknesses in both LER writing and technical reviews. The overall format and content of recent LERs have been good, with exception of the above specific inaccuracies.

3.4 Onsite LER Followup (92700)

The following LERs were selected for onsite followup inspection to determine whether the licensee has taken the corrective actions as stated in the LER and whether responses to the events were adequate and met regulatory requirements, licensee conditions, and commitments. The NRC tracking status is indicated below.

3.4.1 (Closed) LER 91-011, "Reactor Trip Due to Faulty Relay"

The inspector reviewed the revised LER published on August 8, 1991. The licensee submitted a revised LER after the inspectors pointed out that the original report failed to mention the actuation of a main steam isolation signal which occurred following the reactor trip. A violation of 10 CFR Part 50.73 was not cited because, at the time, this omission appeared to be the second of two isolated cases. In addition, the licensee provided some additional information on related corrective action associated with the failed Struthers Dunn 600 series relay. The failed relay prevented the electrical bus supplying two reactor coolant pumps from transferring to the startup transformer following a turbine trip and resulted in the reactor trip on May 28, 1991. The licensee inspected three other similar relays for the electrical buses supplying reactor coolant pumps during the recent outage under Work Authorization 01080665 and reported that no problems were found. Numerous other Struthers Dunn relays were used throughout the plant, but the licensee did not feel that sufficient information was available to indicate that the relay that failed on May 28 was an indicator of a generic problem. The relay failed due to a coil failure caused by degradation of the plastic sleeve surrounding the core. They felt this was an isolated case since previous failures were due primarily to high contact resistance. The licensee indicated that any future malfunctions of Struthers Dunn relays would be investigated to gather data that might determine if the relays had a generic problem. This LER is closed.

3.4.2 (Closed) LER 91-017, "Operation in Technical Specification 3.0.3 for Inaccurate Safety Injection Tank Pressure Indication due to an Inadequate Procedure"

The inspector reviewed the LER and determined that it was complete, accurate, and submitted in a timely manner. The licensee determined that the inaccurate pressure indication for SITs 1A and 2B was due to water in the pressure instrument sensing lines. They believed that the water came from the SITs when they were refilled following maintenance during the last refueling outage. Operating Procedure OP-009-008, Revision 9, "Safety Injection System," required that a drained SIT be refilled to 100 percent and then drained down to its normal operating level under nitrogen pressure. The licensee felt that the procedure was deficient in that it did not require that the instrument line be checked for water following the fill evolution. The pressure instrument lines come off the top of the tanks. The TS violation was due to the fact that indicated pressure was higher than actual nitrogen pressure in the two SITs due to the water in the pressure instrument lines. The licensee indicated that the error was small and would not have significantly affected the predicted postaccident fuel peak clad temperatures.

The inspector reviewed the licensee's long-term corrective action, which consisted of a change to Procedure OP-009-008 to add the requirement to drain the pressure instrument sensing lines following refill of the tanks. The procedure change was issued September 20, 1991, and was considered adequate to prevent recurrence of the problem. The violation of TS described in the LER will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII of the NRC Enforcement Policy (NCV 92003-2). This LER is closed.

Conclusions:

The licensee's performance in dealing with the SIT pressure problem in paragraph 3.4.2 was a strength. Therefore, a violation was not cited, pursuant to Section VII of the NRC Enforcement Policy. The licensee's actions to prevent a recurrence of the failed Struthers Dunn 600 series relay were adequate in that the failure appeared to be an isolated case. Both LERs were well written.

4. ONSITE RESPONSE TO EVENTS (93702)

4.1 RCS Leak

On January 9, 1992, the licensee discovered boric acid crystals and water leaking below SG No. 1. As described in paragraph 4.3 of NRC Inspection Report 50-382/91-31, the licensee could not gain sufficient access to find the exact source of leakage. Radiation levels were too high to gain safe access with the plant at power. The licensee concluded, based on the available information, that it was the SG No. 1 primary cold leg manway gasket that was leaking and began planning an outage to make repairs.

On February 3, the licensee discovered that 150 pounds per square inch (psi) design gaskets were installed on the hot and cold leg primary manways on both SGs, when the gaskets should have been 2500 psi design. The SG vendor, Combustion Engineering (CE), identified the required gaskets in the SG technical manual by Part Number 276-102, "commercial grade," with dimensions and material notes which called for stainless steel and asbestos "Flexitallic Special" or equal. The pressure rating was not specified. The licensee performed an operability determination in accordance with Site Directive W4.101, "Nonconformance/Indeterminate Analysis Process." The determination was documented on February 4, and the licensee concluded that the four primary manways were operable and that no immediate safety concerns existed. This was based primarily on discussion with CE who, in turn, discussed the problem with Flexitallic, the gasket manufacturer. The inspectors noted that the joint design was such that the gasket was completely captured, and that catastrophic failure could not occur. The licensee noted that the remaining three SG manways were not leaking.

4.1.1 Steam Generator Primary Manway Gasket Procurement

The inspector was provided a review by licensee personnel of the procurement history of SG primary manway gaskets. Included in this review was a discussion of the circumstances pertaining to the purchase orders (POs) erroneously specifying 150 psi design gaskets for the application. This error was described to have resulted from a clerical error during transfer of gaskets from the plant constructor's (Ebasco) inventory control to the licensee's inventory control. The transfer requisition, which was prepared by nontechnical licensee personnel with no technical review performed, identified the gaskets by the CE Part Number 276-102 and as 18-inch, 150 psi. No reason had been established for the 150 psi pressure rating, in that the gaskets were not tagged with the rating, and the Ebasco and CE documentation did not indicate any pressure rating. This error was subsequently carried forward to other documents (including POs) without the error being detected.

The inspector reviewed the licensee POs that were applicable to procurement of SG primary manway gaskets (i.e., L-23519-H, WP026851, WP030370, WP040096, and WP04006). It was ascertained from this review that all of the POs were placed with a local distributor and that the following three types of procurement occurred:

4.1.1.1 PO L-23519-H, which was issued on December 14, 1982, identified the gasket size and specified that the gaskets be flexitallic, manway gaskets, 2500 psi, with Type 304 stainless steel backing.

4.1.1.2 POs WP026851 and WP040061, dated August 2, 1989, and April 24, 1991, respectively, identified the gasket size and specified that the gaskets be stainless steel/asbestos, 150 psi. In addition, the POs identified: (1) that the gaskets were intended to be used in SG primary manways, (2) the original CE PO number, (3) the applicable CE drawing and part number, (4) that the gaskets were to be flexitallic type, and (5) the dimensional tolerances listed on the CE drawing. Certain technical and quality requirements were also included in the text of PO WP026851 and by attachment of Procurement Specification PROC-M-100, "Gasket, Spiral-Wound," Revision 1, to PO WP040061. These requirements included chemical limitations and the furnishing of a certificate of conformance.

The installed 150 psi gaskets were determined by licensee personnel to have been procured by PO WP026851. Review by the inspector of receipt documentation for this PO showed that the gasket manufacturer had furnished to the distributor a certificate of conformance which addressed the chemical limitations of the PO. In addition, a final inspection report was furnished by the gasket manufacturer to the distributor which contained a statement of conformance to distributor PO requirements and also identified PO WP026851 as a "customer reference." It could not be concluded whether the "customer reference" signified that PO WP026851 had been transmitted to the manufacturer by the distributor or was simply a notation of the ultimate customer. Licensee examination of the gaskets received for PO WP040061 found that they appeared to be higher pressure gaskets than the 150 psi gaskets that had been specified.

4.1.1.3 POs WP030370 and WP040096, dated December 4, 1989 and April 25, 1991, respectively, identified the gasket size and specified that the gaskets be flexitallic stainless steel. In addition, the POs identified: (1) that the gaskets were intended for steam generator manways, (2) the part number, but without indicating that it was a CE part number, and (3) that the materials were to be furnished in accordance with Purchase Specification PROC-M-100, Revision 1. The POs did not identify a required pressure rating or specify the original CE PO number, CE drawing number, or CE dimensional tolerances. Licensee examination of gaskets received for these two POs found that those furnished to PO WP030370 appeared to be the same as those received for PO WP026851. Those received for PO WP040096 appeared to be a higher pressure design gasket.

The licensee did not consider the primary manway gaskets to be safety-related. This was based, in part, on the specific exclusion by Article NB-2000 in Section III of the American Society of Mechanical Engineers (ASME) Code of gaskets for consideration as pressure retaining material. The licensee's root cause investigation was still in progress as of the end of this inspection, but the preliminary root cause of the problem was determined to be the documentation error that occurred during transfer of the gaskets to the licensee's inventory control. Contributing causes were determined to be not specifying pressure ratings on two of the POs, the vendor supplying a high pressure gasket when a 150 psi gasket was specified, and a misunderstanding that Flexitallic could cross-reference a CE part number and supply the correct gasket.

Observations made by the inspector during review of the procurement history were as follows:

4.1.1.4 The gasket procurement history was an indicator that insufficient attention had been given to technical review of important nonsafety-related procurements.

4.1.1.5 The 150 psi value should have been identified as an error during development of the requirements for PO WP026851. This observation would be contingent on the procurement engineer being cognizant of the technical requirements contained in the original CE PO that was referenced in PO WP026851.

4.1.1.6 The failure to recognize that a 150 psi gasket was not appropriate for primary pressure during the PO technical review was an indicator of a training weakness.

4.1.1.7 The present methods, when procuring through distributors, did not assure that the manufacturer either received the licensee purchase order or was fully cognizant of the procurement requirements (i.e., a certificate of conformance was required from the supplier rather than the manufacturer).

4.1.2 Review of Manway Cover Installation Practices

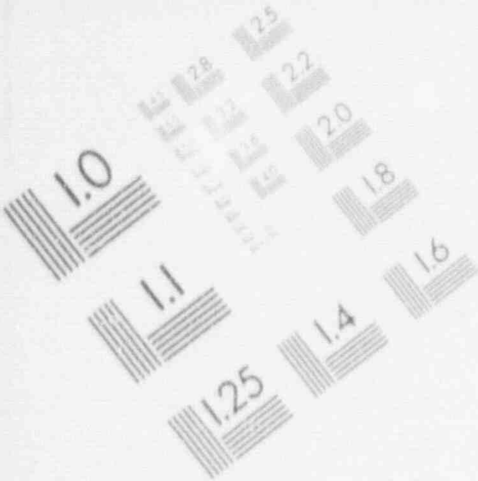
The inspector verified that the thread lubricants used by the licensee for SG primary manway studs were of a type that would not contribute to initiation of stress corrosion cracking (i.e., the lubricants did not contain molybdenum disulfide). In addition, the inspector reviewed Work Authorizations (WAs) 01071648 and 01071582 to ascertain the installation practices that were used for the SG manway covers during the previous refueling outage (RFO-') following completion of eddy current testing. It was noted during this review that the postmaintenance retest listed on page 4 of both WAs was for Operations Quality Assurance to perform a visual inspection for leakage (VT-2) of the SG primary manways at normal RCS temperature and pressure. This visual inspection was signed off as being completed on May 20, 1991, by two different Level II examiners for each SG.

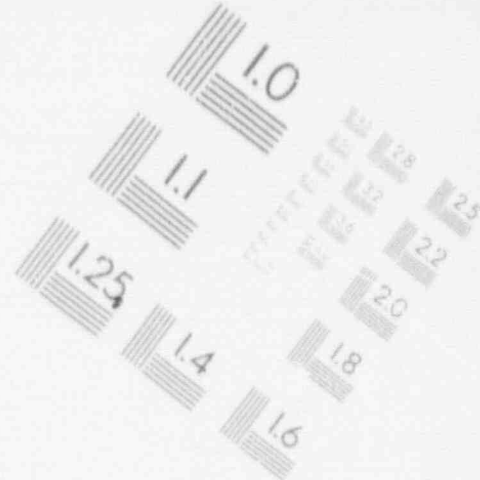
Examination of the two inspection reports that were referenced by the WAs identified, however, that the test temperature was marked "N/A" for the visual examination of the primary manways in each SG. Both inspection reports had been signed as being reviewed by a Level III examiner. In addition, the ASME Section XI Work Package Review Form for the two WAs showed that the opening review by the repair/replacement engineer had identified that a VT-2 inspection was required to be performed at normal operating pressure and temperature. The closing review by the repair/replacement engineer for each WA was signed off without identification of any deviation from the VT-2 requirement. At the inspector's request, the licensee reviewed temperature charts and inspection logs and confirmed that the VT-2 inspections were performed at 490°F, which was below the normal no-load operating temperature of about 544°F. The inspector reviewed ASME Section XI Code requirements and verified that the VT-2 inspection was required by ASME Code to be performed at normal operating pressure and not necessarily at normal operating temperature. However, the WA should have been changed and properly approved to delete the normal operating temperature requirement. The failure to comply with the WA VT-2 instruction indicates a weakness in work control practices and is a violation of Criterion V of Appendix B to 10 CFR Part 50 (VIO 92003-3).

4.1.3 Use of Helical Coil Threaded Inserts on SG Manway Studs

On February 4, the licensee informed the inspectors that they had installed a helical coil threaded insert (helicoil) on one stud for the SG No. 1 hot leg manway and two others on the SG No. 2 cold leg manway during the previous refueling outage completed in May 1991. ASME Boiler and Pressure Vessel Code Case N-496, "Helical Coil Threaded Inserts," permitted the use of helicoils; however, the NRC had not accepted the code case as required by 10 CFR Part 50.55a. On February 5, the licensee sent a letter to the NRC Office of Nuclear Reactor Regulation Project Manager for Waterford 3, informing NRC of the condition and providing some background information. On February 14, the licensee formally requested specific approval for the use of helicoils on any SG manway and to extend the approval to the 3 helicoils already installed. The basis for the request included a 10 CFR Part 50.59 evaluation, CE Calculation CENC-1805, "Waterford Unit No. 3 Steam Generator Manways," which confirmed that helicoils may be used in any or all stud holes, and ASME Code Case N-496, not yet accepted by the NRC in accordance with 10 CFR Part 50.55a. The licensee entered the deficiency (failure to comply with 10 CFR Part 50.55a) in their corrective action program by initiating Quality Notice No. 92-008. As it turned out, the licensee had no need to utilize additional helicoils during the manway gasket replacement. On February 21, the NRC approved the specific application of the three helicoils already installed in the SGs. Failure to comply with the 10 CFR Part 50.55a requirement to apply only those ASME Code Cases that have been determined suitable for use by the NRC would be a violation if the Code Case had been the basis for using helicoils. Since the licensee had a sound technical basis for applying the existing helicoils, there remained a question as to whether or not the helicoils could have been installed absent the Code Case. Therefore, it remained unresolved, as of the end of this inspection period, whether or not NRC regulations were violated. The NRC is in the process of reviewing this issue (UNR 92003-4).

On February 16, the plant was shut down and the licensee confirmed that the RCS leak under SG No. 1 was the primary cold leg manway. The inspectors reviewed



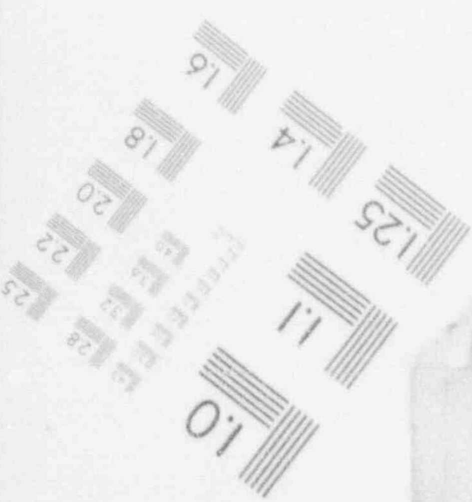


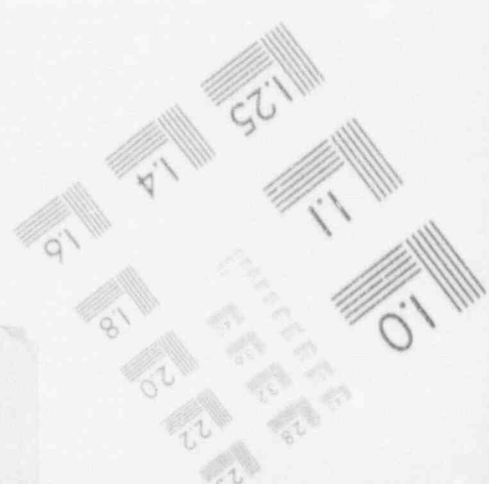
1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"





1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

the video tapes of the leak, which showed some steam coming out the bottom of the manway between two studs and minor leakage coming out of the threads of the nut on a stud at the top of the manway. The licensee decided to cool down the plant, repair the leak, and replace the 150 psi design gaskets discussed above with the correct 2500 psi design gaskets on the hot and cold leg manways of both SGs. The licensee had planned for this decision and had also planned some other outage work that could be accomplished in parallel.

By February 19, the SG No. 1 cold leg manway was removed. The 4.88-inch thick manway cover had boric acid wastage in the area where it contacted the stainless steel cover plate gasket area. The wastage was about 5/16 inch deep from about the 4 o'clock position to the 7 o'clock position. Because this area was needed to properly compress the gasket, even though minimum thickness was not reached, CE recommended machining the cover to remove the wastage, but not to exceed 3/8 inch of material removal. The licensee successfully machined 5/16 inch from the cover face. This restored the flatness and removed the wastage. The SG nozzle face had boric acid wastage at the 6 o'clock position, but under CE guidance and acceptance, the licensee faired in the rough surface by grinding. The stainless steel gasket seating surface was not damaged. The inspectors inspected studs removed from all four manways. The studs removed from SG No. 1 hot leg were free of wastage, except two had minor thread corrosion in a small area that could not be removed. Apparently, there had been a slight RCS leak near these studs for a short time. Three of the SG No. 1 cold leg studs had wastage. One had about 6 threads eaten away and about a 10 percent diameter reduction. This was on the threads extending beyond the nuts which had no load. The two other studs had corrosion on the reduced diameter shank, but very minor reduction in cross section. The licensee replaced all of the corroded or questionable studs and nuts on the SG No. 1 manway.

There was some minor corrosion in spots on the SG No. 1 bowl underneath the manway. CE evaluated the condition and supervised fairing in by grinding. On February 24, while the plant was at 1650 psia and normal operating temperature, the inspectors inspected both SG No. 1 manways and the areas below the manways. There was no evidence of leakage, and all of the boric acid deposits resulting from the leak were removed.

Later that day, the plant was pressurized to normal operating pressure, and the four manways were inspected by the licensee for leakage to satisfy retest requirements. No leakage was found.

4.2 COLSS Margin Adjustment

On February 21, 1992, the licensee informed the inspectors that, prior to the startup following the February 16 planned outage, addressable constants would be conservatively readjusted to reflect a possible increase in the statistical uncertainties that were input to the COLSS and the CPC. This would result in a reduced COLSS margin as it applied to DNBR and PLHGR. On February 20, CE was performing a verification of statistical uncertainties in support of developing a modified combination of statistical uncertainties for COLSS and CPC to be used after Refueling Outage No. 5 in September 1992. They discovered during a scoping analysis that the 3°F uncertainty that had been in use for temperature instruments was closer to 3.9°F. This was because they assumed the licensee was using metering and test equipment accurate to 0.25 percent when in fact it was 0.50 percent. The significance of this issue was that the potential existed that DNBR and PLHGR margins might have been exceeded without a COLSS alarm to alert the operators. The licensee was confident that such was not the case, because there were conservatisms in other parameters contributing to the uncertainty, i.e., installed instrument drift had been much smaller than the assumed value. The licensee initiated a nonconformance condition report and commenced reevaluating the 3.9°F uncertainty. Until it was reevaluated, the licensee stated that the plant would be operated assuming the greater uncertainty. If the uncertainty could not be evaluated back to, or below, the original 3°F, the licensee stated they would determine whether or not any margins were exceeded and make the appropriate reports as required by NRC regulations. Since COLSS monitored licensed full power operating limits using a calorimetric calculation, and it had been most limiting in the past, it was unlikely that any margins were exceeded. The inspectors will monitor the licensee's actions and will track the final resolution of this issue under IFI 92003-5.

4.3 EDG A Valves Out of Position

At 8:28 a.m. on March 11, 1992, one of the licensee's nonlicensed auxiliary operators (NAOs) found the EDG A left bank cranking control air shutoff Valve EGA-302A and the left bank nonfailsafe air supply Valve EGA-404A in the closed position when they were required to be open. He found this condition during a routine tour, and remembered both valves were in the correct open position about the same time on March 10. These were tubing valves located on a control air panel, and the status was easily determined at a glance. The significance of this was that the left bank air start valve (one of two redundant valves) was disabled with Valve EGA-302A closed. Valve EGA-404A being shut had no consequence because this air supply was cross-connected to the right bank air supply. Also, Valve EGA-404A supplied air to EDG trip devices that would be bypassed during an emergency start.

During the timeframe that EGA-302A may have been closed, Air Compressor A1, which was supplying air to the right bank air start valve, was taken out of service for maintenance. Therefore, the only source of starting air was Receiver A1, with no air compressor to maintain pressure. The pressure had dropped to below the low pressure alarm point of 175 psig by about 9:30 a.m. on March 10 and was not restored to the normal pressure of 250 psig until after 12 noon on March 10. EDG A may not have been operable with degraded starting air pressure on the right bank and with the left bank disabled (EGA-302A closed) for up to 3 hours on March 10. TS 3.8.1.1 required both EDGs to be operable during this period, because the plant was operating at full power.

The licensee promptly restored the valves to the proper position after the discovery was made on March 11. They also conducted breaker and valve lineup checks in accordance with the EDG operating procedure and found no other problems. Utilizing a security printout, the licensee also investigated who was in the EDG A room from the time the valves were seen in the correct position on March 10, until the valves were found out of position on March 11. As of the end of this inspection period, the licensee was still in the process of contacting the approximately 40 people who were in the room.

At about 6 p.m. on March 11, the licensee informed the inspectors that on Monday, March 9 (which was a compressed work week day off for most employees), the NAOs reported discrepancies in waste control panel valve positions compared with information they had received during shift turnover. This panel was located in a passageway near the exit from the radiologically controlled area. While this had no safety significance, it added to the licensee's concerns about unexplained valve mispositioning. The licensee included the investigation on this problem with the EDG A problem above, because there might have been some connection as to the cause.

The licensee directed watchstanders to increase vigilance over the plant systems and to watch for suspicious activity. As of the end of this inspection period, the licensee had not made a determination of whether or not EDG A was operable during the 3-hour period on March 10 when right bank starting air pressure was below the alarm point. Also, the licensee had not established a cause for the two left bank control air supply valves being out of position. Therefore, it remains unresolved as to whether or not a violation of NRC regulations occurred (UNR 92C03-6).

Conclusions:

Based on a review of past installation and retesting practice used on SG primary manways, the inspectors identified a violation involving failure to follow written instructions (paragraph 4.1). Weaknesses were identified in the licensee's procurement process in that inadequate controls were placed on the procurement of commercial equipment that could have an effect on important balance-of-plant, or safety-related equipment. The licensee's actions to repair the leaking SG manway were excellent. It remains unresolved as to whether or not the previous installation of helicoils was in violation of NRC regulations; however, they were installed using a sound technical basis. The licensee's NAO exhibited excellence in the performance of his routine inspection tour by finding the EDG A control air supply valves out of position (paragraph 4.3). It remains unresolved as to whether or not EDG A was operable during the period Compressor A1 was out of service and the control air supply valve was inappropriately closed.

5. 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 WAs, procedures, TS, and appropriate industry codes or standards.

5.1 WA 01055179, 01087318: Wet Cooling Tower B Maintenance

On February 10, 1992, the inspector observed maintenance on the wet cooling tower for Auxiliary Component Cooling Water System B. One WA was written to replace a broken spray header nozzle and another was to perform a periodic inspection of the wet cooling tower for signs of deterioration or damage. The inspector reviewed the WAs and found them properly prepared, approved, and adequate for the work being performed. The persons performing the maintenance were familiar with the equipment being maintained. No problems were identified.

5.2 WA 01086148: Packing Adjustment and Subsequent MOVATS Test of Valve MS-401B

On February 7, 1992, the inspector observed portions of the MOVATS testing on Emergency Feedwater Pump A/B steam supply Valve MS-401B. In November 1991, a packing leak was identified on Valve MS-401B. The inspectors noted that the leak slowly deteriorated while awaiting maintenance action. On or about January 31, 1992, the inspectors expressed concern to the Shift Supervisor that the leakage appeared quite severe. By February 7, the packing was finally adjusted. The technicians retested the valve in accordance with Maintenance Procedure ME-007-027, Revision 5, "Using MOVATS 2150/2151 System for Test MOV." The inspector reviewed the data and found no significant problems. After the MOVATS test was completed and the test equipment removed, the operators conducted a retest of the valve in its normal configuration by performing Surveillance Procedure OP-903-046, Revision 9, "Emergency Feedwater Pump Operability Check." The valve and pump operated satisfactorily; however, the valve packing began to leak slightly. Since the valve could not be safely repacked while the plant was operating (the valve could not be isolated and depressurized because it was piped directly from the main steam header upstream of the main steam isolation valve), the licensee chose to initiate a new CI report and close out the above WA. The valve packing appeared to be leaking to an acceptable degree.

While reviewing the WA, the inspector noted instructions to obtain a clearance, remove the packing, and install new packing in the valve if leakage could not be stopped by adjusting the existing packing. In view of the plant conditions (operating at full power) and the fact that MS-401B could not be isolated from the steam header, these instructions did not appear appropriate to the circumstances. The inspector discussed this with the Mechanical Maintenance Superintendent and expressed it as a weakness in planning.

During the outage, the valve was repacked. A minor burr was found on the valve stem which appeared to be a cause of packing leakage. The burr was removed and the valve successfully MOVATS retested prior to the plant startup following the outage. After several days of plant operation at power, the inspector checked the packing for leakage and found none.

5.3 WA 01089639: Repair of Essential Chiller B Evaporator

On January 28, 1992, Essential Chiller B was taken out of service to perform an overhaul and to implement five design changes developed to improve performance. On or about February 3, while the overhaul was in progress, a workman inadvertently bumped the refrigerant isolation valve which isolated the refrigerant reservoir from the drained evaporator, releasing refrigerant back to the evaporator. The partially opened valve apparently acted as an expansion valve, reducing the released refrigerant temperature to below freezing. The tubes were still full of water and over 70 tubes were frozen. After checking, the licensee found that most of the 70 tubes were ruptured. The above WA was implemented to replace the damaged tubes and perform the required retests. The repairs were done with the assistance of a Carrier service representative, with special tools for removing and replacing tubes furnished by Carrier. The inspector reviewed the WA and found the instructions to be sufficiently detailed and well engineered to assure a quality repair. The evaporator shell had to be cut open to enable the mechanics to remove the damaged and swollen tubes by cutting them and pulling them out the side. They could not be pulled through the tubesheet, which would be the normal method, because of the swelling. The major portions of this work were observed by the inspector on February 11-13.

The work was being done in a professional manner and good work practices were executed. ASME pressure vessel code requirements were incorporated into the documentation and were met. When needed, a firewatch was provided in accordance with the licensee's procedures when hot work was being done. On March 6, all five modifications were completed and the machine had been cleaned, evacuated, charged with Refrigerant 12, and leak tested. The machine was started up in accordance with the operating procedure and loaded. The inspector observed no abnormalities and the compressor functioned smoothly. The 5 modifications were: (1) a motor ammeter was added to the control panel, (2) a dehydrator was added which could be monitored and the water drained without shutting down the machine, (3) an oil recovery line with sightglass, (4) a fixed motor current feedback resistor, and (5) a new modulating hot gas bypass valve. The acceptance tests specified for the modifications were completed satisfactorily except for the hot gas bypass modification, Station Modification 3176. The essential chillers each had a hot gas bypass which was designed to open under very low load conditions to prevent the units from tripping off the line on low suction pressure. They had not worked well, and consequently there have been many low load shut downs, especially during cool weather. This has not been a safety problem in that when a load was sensed the units would automatically restart (after a time delay). The hot gas bypass modification added an air operated valve with pneumatic-electric controls designed to modulate the bypass during low load conditions. This new feature did not function when operationally tested. The maintenance technicians concluded, with engineering assistance, that the wiring design was flawed and needed redesign and alteration before it would work. The inspectors met with Design Engineering to determine the cause of the problem. The hot gas bypass control vendor had apparently miscommunicated with the designer over what adjustments must be made if an isolation device was not utilized in the circuit. Consequently, the design called for wiring connections that would not work. This appeared to be an isolated case, and it was detected by the acceptance test and, therefore, was not of significant concern. The licensee corrected the design on March 13, and the inspectors will follow up on satisfactory completion of the modification and the acceptance test during the next inspection period.

5.4 WA 01090142: EDG B Fuel Oil Storage Tank (FOST) Cleanup

On February 19, 1992, the inspector observed the licensee using a fuel tank maintenance contractor to clean up the diesel fuel in the FOST for EDG B. A portable filtration unit was used to recirculate the fuel and remove particulate matter. The fuel met the TS requirements for cleanliness, but the licensee desired to reduce the fuel contaminants prior to reaching a required action level. The WA which was used to connect the filtration unit to the tank was reviewed and found to be properly prepared and approved and adequate for the work. The system engineer for the EDGs was directing the work. A change to Procedure OP-003-009, Revision 7, "Fuel Oil Receipt," was made to align the tank for the recirculation. The change required closing the discharge valve for the fuel transfer pump, which made the EDG inoperable. It still would have emergency started and sufficient time would have been available to open the pump discharge valve before the feed tank ran out of fuel. The unit was in Mode 5 and only one EDG was required to be operable by TS. The licensee intended to keep the EDG available during the evolution since the unit was on shutdown cooling (SDC) with the RCS drained to midloop to facilitate replacing the SG primary manway gaskets. The tank was recirculated and filtered for approximately 24 hours and particulates were reduced from 26.0 mg/liter down to 1.14 mg/liter. The FOST for EDG A was filtered following restoration of the tank for EDG B with similar results. No problems were noted with the work.

5.5 WA 01089136: Investigate Possible Seat Leakage for Valve SI-243

On February 19, 1992, the inspectors observed work on High Pressure Safety Injection Check Valve SI-243. The valve was suspected of leaking back through its seat and contributing to the leakage from SIT 2-A. The tagout for the work was reviewed and found to be adequate to isolate the valve. The WA was reviewed and found to be properly prepared and approved. The package did not contain specific instructions for reinstalling the valve bonnet to insure that the seal ring was properly seated. SI-243 was an Anchor-Darling check valve similar to RC-303 which developed a significant leak after the fourth refueling outage due to the seal ring being cocked (see NRC Inspection Report 50-382/91-18). The mechanic assigned to work the valve stated that all the maintenance personnel qualified to work these valves had been adequately trained subsequent to the RC-303 problem and that more specific work instructions were not needed. The inspector later discussed this with the Mechanical Maintenance Assistant Superintendent and he indicated that he was satisfied that current training of his people was sufficient for working on this type of valve. Consideration was being given to adding detailed instructions to their valve maintenance procedure to ensure assembly techniques obtained from the vendor were not lost. The inspector observed work on the valve and noted good radiological work practices. The valve was disassembled, cleaned, and inspected. The valve seat and disk were in excellent condition and no further rework was necessary. No other problems were identified with the work.

Conclusions:

Overall performance of maintenance activities observed during this inspection period was excellent. Work was accomplished in a timely and professional manner. A minor weakness was noted in the planning and procedures aspect of the work observed, including errors in the hot gas bypass modification on Essential Chiller B, causing it to fail the acceptance test.

6. BIMONTHLY 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 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.

6.1 Procedure MI-03-504, Revision 3, "Broad Range Gas Detection System Channel Functional Test and Calibration"

On February 11, 1992, the inspector observed the weekly calibration of the Broad Range Gas Monitor "B," which was required by TS Surveillance Requirement 4.3.3.7.3. The calibration was performed in accordance with Section 8.2 of Procedure MI-03-504. The surveillance test was properly authorized and performed by qualified personnel in accordance with an approval procedure using calibrated test equipment. The detector was calibrated using Benzene as the calibration gas with the instrument span corrected to the standard gas, Acrolein, in accordance with Attachment 10.1 of the procedure. The surveillance procedure was considered adequate for the task and followed well by the technicians. No problems were identified.

6.2 Procedure PE-005-006, Revision 4, "Fuel Handling Building Ventilation System Surveillance"

On February 11 and 12, 1992, the inspector observed the performance of sections of PE-005-006 for both trains of the FHB emergency filtration units. The procedure instructed surveillance testing of the units as required by TS Surveillance Requirements 4.9.1.2. The sections of PE-005-006 that were being performed were 8.1, "Pretest Visual Inspection," 8.5, "Airflow Capacity and HEPA/HECA DP Check," 8.6, "In-Place Leak Test, HEPA Filters," and 8.7, "In-Place Leak Test, Adsorbent." The inspector verified that the testing was properly authorized and was being performed in accordance with an approved procedure. Properly qualified personnel were performing the testing using calibrated test equipment. The licensee used contract personnel to do the testing and they were directed by a licensee system engineer. The inspector reviewed the training and qualifications of the test personnel and the calibration certification for their test equipment. No problems were identified.

On February 11, the inspector observed testing on the Train A filtration unit. He noted that, with the testing well underway, a significant number of test steps, prerequisites, and data sheets had not been signed-off or completed even though it appeared that the steps had been done. This was discussed with the system engineer directing the test and he confirmed that the work had been performed but that the documentation had not been kept current. The procedure was reviewed and it was determined that no steps had been performed which required signatures prior to proceeding. On February 12, the inspector reviewed the procedure for the sections which were completed on the Train A unit and the documentation was complete and all applicable acceptance criteria were met. The inspector witnessed performance of Section 8.5, "Airflow Capacity and HEPA/HECA DP Check," for the Train B unit and noted that adjustments had to be made to the unit inlet damper, HVF-202B, to bring the airflow down into the required range. Airflow was remeasured and met the acceptance criteria. No other problems were noted with the surveillance test.

6.3 Procedure OP-903-033, Revision 9, "Cold Shutdown IST Valve Tests"

On February 23, 1992, the inspector observed the performance of OP-903-033 for Valve SI-405A. The test was being performed as a retest for the valve after the nitrogen pressure was reduced in the valve's closing accumulator (See paragraph 7) as required by TS 4.0.5. The test was properly authorized and performed in accordance with an approved procedure. A qualified individual performed the test. The valve closing time met the test acceptance criteria. No problems were identified.

6.4 Procedure OP-903-008, Revision 3, "Reactor Coolant System Isolation Leakage Test"

On February 23, 1992, the inspector observed the performance of Procedure OP-903-008 for Valves SI-405A and SI-405B. The test was being performed for the valves as required by TS Surveillance Requirement 4.4.5.2.3.b following maintenance on the valves. The test was properly authorized and performed in accordance with an approved procedure by qualified individuals. Both valves met the TS and procedural acceptance criteria for seat leakage. No problems were identified.

Conclusions:

Surveillance testing continued to be a strength at Waterford 3. A minor weakness was identified during FHB ventilation system testing in that the test director, who was a system engineer, failed to sign off completed steps as they were done. This was a poor practice.

7. 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.

During the 10-day outage to replace SG manway gaskets, the inspectors frequently monitored control room activities while the plant was in reduced inventory conditions, the inspectors monitored the licensee's compliance with the requirements of Procedure OP-001-003, Revision 13, "Reactor Coolant System (RCS) Drain Down," which contained special precautions and requirements for monitoring RCS level and SDC system operation when the RCS was partially drained. The licensee maintained redundant indicators of RCS level, a dedicated operator to monitor SDC system operation, and cognizance of activities that had the potential for interrupting SDC, or containment integrity in the event that SDC was lost, as required by NRC regulations.

On February 17, while attempting to place SDC in service, the operators were unable to open one of the Train A SDC suction valves from the RCS hot leg, Valve SI-405A. The redundant Train B was successfully placed in service, that is, Valve SI-405B opened. The licensee found that the hydraulic actuator pressure switch setpoint had drifted downward by about 150 psi and, as a consequence, the actuator could not generate sufficient hydraulic pressure to unseat the valve. The switch was reset and SI-405A was opened. For the duration of the outage, SI-405A and -B were gagged open, which was a normal practice to prevent inadvertent loss of SDC and isolation of the low temperature over-pressure reliefs from the RCS.

The inspectors followed up on the actions being taken by the licensee to address the SI-405A failure. During the previous refueling outage, new Paul-Munroe hydraulic open, nitrogen pressure close, actuators were installed on the valves to improve reliability. The first time they were called upon to open, one failed. The purpose of the pressure switches was to maintain hydraulic opening pressure at 2975 plus or minus 25 psig. The pressure switches had an adjustable setpoint range of 800 to 2800 psig (increasing), according to the vendor manual but, upon consulting with Paul-Munroe, the licensee was told that since the maximum recommended system pressure was 3000 psig and proof pressure was 5000 psig, it was acceptable to set the switch at 2975 psig.

The licensee told the inspector that exact replacement switches were on hand, the setpoint for SI-405B would be checked, and engineering was evaluating, for the long term, whether to adjust the hydraulic and/or nitrogen pressure to lower operating values. Upon checking the switch on SI-405B, the licensee found that it had drifted down 85 psig. Nitrogen pressures were verified correct for both valves. On the basis of the manufacturer's assurance that it was acceptable to use the pressure switches even though the setpoints were beyond the design adjustment range, the license indicated an intent to start up from this outage and operate with no further action on SI-405A and -B until Design Engineering completed its long-term evaluation. The inspector expressed concern that no further immediate corrective action was unacceptable. Both valves had demonstrated a pressure switch drift, and there was no assurance that either or both would not drift during power operation such that they might not perform their intended safety function. This issue had safety significance, because the valves must open to provide SDC and RCS low temperature over-pressure protection following a small break loss of coolant accident. The valves were located in the containment building and, as such, would not be accessible during such an accident scenario.

In response to the inspector's concern, the licensee reduced the nitrogen pressure by 160 psi to provide a margin for potential hydraulic pressure switch drift. The nitrogen pressure alarm was also changed accordingly. The licensee used the proper administrative controls, reviews, and approvals. The change was made consistent with 10 CFR Part 50.59 requirements. The inspector reviewed the documentation and found no problems. The licensee also placed the replacement pressure switches in an environment approximating that of the containment during operation, so that the setpoint could be monitored for drift on a periodic basis. If these switches drifted, the licensee would check (and adjust, if necessary) the installed switches. The licensee's actions to reduce the nitrogen pressure on SI-405A and -B, with the appropriate engineering considerations, coupled with monitoring the setpoints of the replacement switches, was considered appropriate. Failure to take prompt and appropriate corrective actions without the prompting of the NRC inspectors is considered a weakness in the licensee's staff to recognize and apply the correct priority to what might have been a significant condition adverse to quality. The inspectors will follow up on the long-term corrective actions taken by the licensee (IFI 92003-7).

For the duration of the planned outage, close management controls and involvement was evident. Through the plan-of-the-day and plan-of-the-evening meetings the inspectors were able to keep abreast of many of the challenges and how they were dealt with. Since manpower resources were limited, priorities were kept in focus. Health Physics personnel resources were strained by the high work load. To help relieve this, the licensee enlisted the aid of volunteers from the administrative staff to assist. Several volunteers from the secretarial staff appeared at the containment control point and they were very helpful and effective in keeping operations at the control point running smoothly. This was a positive aspect of the good teamwork frequently observed at Waterford 3.

On February 24, while the RCS was at normal operating temperature and pressure (Mode 3), the licensee performed an inspection of repairs made to correct RCS leakage, and also the SG primary manway gaskets, as discussed in paragraph 4.1 above. Prior to the outage, hot leg injection Check Valve SI-512B had been leaking past the hinge pin cover gaskets. Since opening this particular valve involved a high degree of risk in terms of potential loss of SDC (see NRC Inspection Report 50-382/91-17), the licensee decided to replace the four studs and nuts holding each of two cover plates in place, with higher strength studs and nuts. In this manner, higher torque could be applied, thus compressing the gasket to provide a better seal to stop the leak. This was done, and during the inspection there was no leakage found. However, three of the four nuts on one cap were cracked, as were two of the nuts on the other cap. The cracks went all the way through one side of each nut in question. Maintenance, with the concurrence of the Duty Plant Manager, secured the caps with a "C" clamp and added a nut to each stud (the studs had surplus length), and then replaced all of the nuts one at a time. The replacement nuts came from a different source, substituted in accordance with the licensee's procedures. This action was timely and appropriate and prevented subjecting the plant to an unnecessary pressure and temperature transient.

The cracked nuts were machined from liquid quenched and tempered ASME SA-194 Grade 6 stainless steel by NOVA Machine Products Corporation of Middleburg Heights, Ohio. The licensee had purchased 24 nuts on February 5, 1992, and some of the unused nuts in the warehouse were similarly cracked. The licensee accounted for all 24 nuts and noted that none were installed elsewhere in the plant. The cracked nuts were sent to an independent laboratory for failure analysis, and NOVA was informed of the problem. The licensee informed the inspector that NOVA was very responsive and had commenced a search to determine if any other customers had purchased fasteners made from that heat number of bar stock. They were also determining reportability pursuant to 10 CFR Part 21, which was invoked by the purchase order for the 24 nuts. The inspectors will monitor the licensee's actions on this problem.

On February 24, the resident inspectors conducted a detailed inspection tour of the reactor containment building as the licensee heated up the plant for startup. The inspectors verified that no foreign material was in the safety injection recirculation sump, and that there was no loose material in containment that could block the sump screens during a postulated accident. The inspectors discussed several minor deficiencies and questions with the shift supervisor. These were addressed to the inspectors' satisfaction prior to startup. Although there was limited work done, the cleanup of boric acid deposits and overall housekeeping in containment was excellent.

On February 27, while the plant was operating at full power, the inspector noted a large number of scaffolds erected in the Safeguards Rooms, which housed the emergency core cooling system pumps. The scaffolds had just been erected to support smoke detector surveillance testing. Some of the scaffolds were attached to structures that support seismic pipe supports for safety-related systems. The inspector reviewed the documentation required by Procedure NOCP-207, "Erecting Scaffold," and found that the appropriate engineering reviews were made. Still concerned about the large number of scaffolds with a weekend coming up, the inspector was assured that the surveillance would be quickly implemented, and overtime was authorized to get the scaffolding out of the safeguards rooms at the earliest opportunity. The inspector followed up after the weekend on March 3 and found that the scaffolding was removed. The licensee's control of scaffolding has improved since the subject was brought up as a concern in April 1991 (See NRC Inspection Report 50-382/91-09).

Conclusions:

The licensee's performance in executing the planned outage was excellent. Close management involvement, maintenance of appropriate priorities, and a high sense of concern and vigilance over operations during reduced RCS inventory all contributed to the orderly completion and success of the outage. However, the inspectors identified a weakness in the licensee's handling of SI-405A and -B pressure switches drift. Only after the inspectors intervened did the licensee take action to ensure there was sufficient margin to ensure the valves would open if called upon. Housekeeping during and after the outage was a strength. The inspectors noted a distinct improvement in this area over this inspection period.

8. RELIABLE DECAY HEAT REMOVAL DURING OUTAGES (TI 2515/113)

On February 20 through 24, 1992, the inspectors reviewed the licensee's procedures and practices in dealing with outage activities which had the potential for contributing significantly to a loss of capability to remove decay heat from the reactor. The outage conducted during this period involved core heat removal operations while the RCS was drained to midloop. No major safety concerns were identified; however, the licensee was still in the process of refining and developing outage risk assessment practices.

Information obtained in accordance with Temporary Instruction No. 2515/113 will be transmitted to the Reactor Systems Branch, NRC Office of Nuclear Reactor Regulation, for review as directed by paragraph 2515/113-04.

9. SUMMARY OF TRACKING ITEMS OPENED IN THIS REPORT

The following is a synopsis of the status of all open items generated, closed, and left open in this inspection report:

IFI 90022-1 was closed.
IFI 90024-2 was closed.
VIO 90026-5 was closed.
VIO 91013-1 was closed.
VIO 91021-1 was closed.
VIO 91021-3 was closed.
LER 91011 was closed.
LER 91017 was closed.
LER 91022 was closed.
LER 92001 remained open.

VIO 92003-1, Failure to meet 10 CFR Part 50.73 requirements, was opened.
NCV 92003-2, Operation in TS 3.0.3 due to incorrect SIT pressure was identified and is closed.
VIO 92003-3, Failure to comply with instructions, was opened.
UNR 92003-4, Resolution of Helicoil Issue, was opened.
IFI 92003-5, Followup on COLSS/CPC Uncertainty Evaluation, was opened.
UNR 92003-6, Resolution of EDG A operability during valve mispositioning, was opened.
IFI 92003-7, Followup on actions for SI-405A & -B, was opened.

10. <u>EXIT INTERVIEW</u>

The inspection scope and findings were summarized on March 13, 1992, 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.