ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-498/95-25
50-499/95-25

Licenses: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company
P.O. Box 1700
Houston, Texas

Facility Name: South Texas Project Electric Generating Station, Units 1 and 2

Inspection At: Matagorda County, Texas

Inspection Conducted: September 25-29, 1995

Inspectors: W. M. McNeill, Reactor Inspector, Engineering Branch
Division of Reactor Safety

P. A. Goldberg, Reactor Inspector, Engineering Branch
Division of Reactor Safety

Approved: [signature] 10-26-95
Chris A. VanDenburgh, Chief, Engineering Branch — Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of followup on previous inspection findings.

Results (Units 1 and 2):

Engineering

- The licensee prepared comprehensive closeout packages, which assisted the review of each open item.
- The inspection confirmed that a calculation assumption for the control room minimum temperature was not supported by procedural or administrative controls. Although the failure to translate this design

9511010172 951027
PDR ADOCK 05000498
Q PDR

basis into procedures or administrative controls was a violation, the inspectors concluded that it was of minor safety significance because the combination of both cold weather and setting of the control room to less than 72°F was rare. Therefore, the violation was not cited (Section 2.6).

- As indicated in NUREG 1517, "Report of the South Texas Project Allegations Review Team," Section 4.2.2 , the inspection confirmed that "pen and ink" changes in Work Authorization AN-330313 increased the scope of activities authorized. Although this instance was a violation of Administrative Procedure OPGP03-ZA-0090, "Work Process Program," Revision 8, the inspectors determined that these unauthorized changes occurred infrequently, were of little safety significance, and had been identified by the licensee's corrective action program. Therefore, the violation was not cited (Section 2.11).

Summary of Inspection Findings:

- Violation 498;499/9416-01 was closed (Section 2.1)
- Violation 498;499/94202-05 was closed (Section 2.2)
- Inspection Followup Item 498;499/9331-69 was closed (Section 2.3)
- Inspection Followup Item 498;499/9350-11 was closed (Section 2.4)
- Inspection Followup Item 498;499/9404-01 was closed (Section 2.5)
- Inspection Followup Item 498;499/9404-02 was closed (Section 2.6)
- Inspection Followup Item 498;499/9416-02 was closed (Section 2.7)
- Licensee Event Report 498/92-018 was closed (Section 2.8)
- NUREG-1517 Paragraph 4.2.2 was closed (Section 2.09)
- NUREG-1517 Paragraph 4.6.1 was closed (Section 2.10)
- Licensee Event Reports 499/93-011, 499/94-001, 499/94-003, 499/94-005, and 498/95-003 were closed (Section 3.0)

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

During this inspection period, both plants were at 100 percent power.

2 FOLLOWUP ON ENGINEERING OPEN ITEMS (92903)

2.1 (Closed) Violation 498;499/9416-01: Failure to Write a Station Problem Report for a Loose Hold Down Stud Nut on Fuel Injection Pump 2L of Standby Diesel Generator 22

Background

This violation occurred because the licensee failed to initiate a station problem report on a loose hold down stud on Fuel Injection Pump 2L. This failure was significant because it was a precursor to failure of the stud for Fuel Injection Pump 6L on April 14, 1994.

Corrective Actions

As corrective actions to this violation, the licensee replaced and properly torqued the bolts on Fuel Injection Pump 2L. The licensee also replaced the hollow studs with new solid studs on all three of the Unit 2 standby diesel generators and on two of the three Unit 1 diesels. Installation of the solid studs on the third Unit 1 diesel generator was scheduled to be completed in July 1994. In addition, the licensee stated that all maintenance managers and the crew supervisor involved in the event had been retrained in the importance of immediate station problem reporting, and that the event would be included in the material for the next human performance day scheduled in the fall of 1994.

Inspector Actions

The inspectors verified that all of the hollow studs on the fuel injection pumps for the Unit 1 standby diesel generators had been replaced with solid studs. The inspectors reviewed Work Authorization 94012821 completed on June 22, 1994; Work Authorization 94012822 completed on July 26, 1994; and Work Authorization 94012823 completed on June 6, 1994; which all confirmed replacement of the studs.

The inspectors also reviewed Station Problem Report 941222, dated June 8, 1995, which was initiated because of the failure to prepare a station problem report after discovering the first loose stud. Part of the corrective actions included discussing the importance of generating an immediate station problem report with maintenance personnel. The inspectors also reviewed the training records for a training course titled, "SPR 941222," which was presented to the maintenance supervisors in four sessions in July 1994. In addition, the inspectors reviewed a summary of the items presented at the October 27, 1994, human performance day. The failure to report significant deficiencies on the loose stud on the diesel fuel injection pump was discussed.

The inspectors also noted that NRC Inspection Report 50-498; -499/95-19, documented an inspection of the licensee's corrective action program at South Texas Project. The inspection report stated that the station problem report process had been eliminated by the licensee in October 1994 and replaced with a condition report process. The report concluded that the new corrective action program was effective.

Conclusion

The inspectors found that the licensee's corrective actions were responsive to the violation.

2.2 (Closed) Violation 498;499/94202-05: Two Examples of the Failure to Accomplish Activities in Accordance with Procedures

Background

The first example of this violation occurred because an engineer did not identify all the drawings that required change as a result of a design change. During a "back end" review, the licensee identified several additional drawings that required updating; however, the licensee had not initiated design change notices to accomplish these revisions. The second example occurred because the record of audits on the temporary modification process were not in the proper location.

Licensee's Corrective Actions

As corrective action to the first example, the licensee revised Plant Change Form DG-179331. As a further preventive step, the licensee had implemented a previously planned revision to the plant change form program in late 1993. The licensee also revised the plant change program in late 1994. The licensee trained the engineering staff on the revised form and program. The new program stressed tracking of related change activities.

As corrective action to the second example, the licensee audited all current temporary modifications and documented them appropriately. The licensee also significantly improved the temporary modification program during the past 2 years, which included the addition of a full-time coordinator. In addition, the licensee committed to maintain temporary modifications at a minimum to reduce the need for auditing temporary modifications. As result, the licensee dropped the procedure requirement for auditing temporary modifications.

Inspector Actions

The inspectors verified the closed status of Condition Report 95-043 written on the first example and Condition Report 95-644 on the second example. In addition, the inspectors reviewed three recently installed modifications and verified that the valves added by the modification were included in the inservice testing design basis document. The inspectors also verified that the licensee had minimized the number of temporary modifications--only three temporary modifications existed on Unit 1, seven temporary modifications existed on Unit 2, and one temporary modification existed common to both units. The temporary modifications installed dealt with removal of a nuisance alarm, bypass of a sample isolation valve, and similar subjects. Therefore, the licensee's action to delete the administrative requirement for auditing temporary modifications appeared reasonable.

Conclusion

The inspectors concluded that the licensee's corrective actions were responsive to the violation.

2.3 (Closed) Inspector Followup Item 498;499/9331-69: The Licensee's Response to Bulletin 88-08, "Thermal Stresses in Piping Connected to the Reactor Coolant System"

Background

NRC Bulletin 88-08 addressed potential cracking in piping connected to the reactor coolant system due to thermal stratification, cycling, and striping. The licensee responded to the bulletin by letter, dated September 28, 1988. The licensee actions included installation of temporary instrumentation to provide continuous monitoring of the piping for leakage and adverse temperature distributions. The licensee evaluation did not consider thermal cycling a problem when critical weld locations were 20 pipe diameters from the reactor coolant loop nozzles.

The inspectors were concerned that the licensee's assumption of using 20 pipe diameters was inconsistent with published data, which showed possible turbulence after a piping penetration of up to 23 pipe diameters. The nuclear steam supply manufacturer (Westinghouse Electric Corporation) and the Office of Nuclear Reactor Regulation discussed the assumption of 20 pipe diameters in a meeting in NRC Headquarters on November 8-10, 1993. This meeting was held to discuss the licensee's activities to resolve the NRC bulletin. During the meeting, the licensee discussed the phenomena, their evaluation methodology, and their monitoring and analysis methods.

Inspector Followup

As a result of the technical meeting, the NRC issued a request for additional information, and received the following reports in response:

- ASME Class 1 Stress Report for Normal and Alternate Charging Lines,
- ASME Class 1 Stress Report for Pressurizer Spray and CVCS Auxiliary Spray Lines, and
- ASME Class 1 Stress Report for Pressurizer Spray Line Vent Addition.

The NRC forwarded these reports to the Brookhaven National Laboratory for further evaluation. Also, the licensee submitted Westinghouse Topical Reports WCAP-12598, "NRC Bulletin 88-08 Evaluation of Auxiliary Piping for South Texas Project Electric Generating Station Units 1 & 2," dated May 31, 1990, (proprietary) and WCAP-12646, "NRC Bulletin 88-08 Evaluation of Auxiliary Piping for South Texas Project Electric Generating Station Units 1 & 2," dated May 31, 1990 (non-proprietary). On April 11, 1994, the NRC documented acceptance of the licensee's approach to Bulletin 88-08 in a memorandum from Kokajko (NRC) to Cottle (HL&P). This acceptance was with a caveat on the "turbulence penetration" phenomenon. The memorandum said that the NRC would perform a generic review and provide additional plant-specific safety evaluation of the affects of this phenomenon on long-term operation. The inspectors verified with the Office of Nuclear Reactor Regulation project manager that he is tracking this generic review and the need to request additional information of the licensee.

Conclusion

The inspectors concluded that the licensee's actions were responsive to the original concern. The inspectors closed this item for regional inspection purposes and confirmed that Office of Nuclear Reactor Regulation will track future actions on the plant-specific evaluation.

2.4 (Closed) Inspector Followup Item 498;499/9350-11: Program Expectations for the System Engineers Greatly Exceeded the Resources Provided

Background

An NRC inspection (NRC Inspection Report 50-498;499/93-50) performed in April 1993, as followup to the 1993 Diagnostic Evaluation identified several obstacles for the performance of system engineers. These included a large number of system assignments, a large amount of emergent work, inaccurate databases, and a lack of individual computer systems. The inspection also identified problems involving: incomplete monthly walkdowns and documentation, a lack of detail and trending in system report cards, a lack of knowledge of service requests and modifications, and deficient training. In addition, management did not oversee the program and supervisors had inconsistent standards.

Inspector Followup

The inspectors found that the licensee had developed an operational readiness plan, which addressed restructuring system engineering, improving training and qualification, and reducing the burden on system engineers. In addition, the licensee revised the system engineer guidelines. These guidelines took the form of "desk top" type instructions and were not procedures required by the quality assurance program. The new guidelines provided management expectations on system walkdowns and system report cards. They also included a list of attributes for providing detail in system walkdowns. The inspectors noted that during recent months, system engineers had performed 140 to 150 walkdowns per month. In addition, the inspectors noted that these guidelines included the identification of trend information in system report cards. The guidelines clearly identified that system engineers must be aware of all service requests and modifications on their systems. The inspectors also noted that new training requirements were provided in the new guidelines and that basic system engineering training was complete. The licensee plans completion of system-specific or expert training by the end of 1996.

The inspectors noted that the licensee had assigned the system engineers approximately two to three systems per engineer. In a few cases, no more than six minor and related systems were assigned. The inspectors noted that the licensee's method of designating systems had resulted in many more systems than typically found at other facilities. However, only 50 of the 202 total systems were major and required a system engineer.

The licensee had developed many mechanisms to provide management overview of system engineering. For example, system performance measures and reliability rates provided success information. In addition, rate of increased frequency of inservice testing, individual component failure rates, and a "black board" in the control room were measures of system success. The licensee's 1995-1999 Business Plan also established performance goals for system engineering to assure accomplishment of walkdowns, health reports, system notebooks, and training. The inspectors also noted that the licensee has reduced the overtime hours of system engineers over the past year. The overtime in the past year was 25 to 30 percent of previous years overtime use.

The inspectors also noted that the recent engineering and technical support team inspection concluded that system engineering was well documented and implemented. NRC Inspection Report 50-498; -499/94-202 documented this conclusion with the observation that walkdown reports and system health reports were valuable tools.

The inspectors also reviewed the training records of five system engineers, eight current walkdown reports, three quarterly reports, and interviewed eight system engineers. The inspectors found there was no change in system engineering since the earlier NRC engineering report.

Conclusion

The inspectors concluded that the licensee's actions were responsive to the original concern.

2.5 (Closed) Inspector Followup Item 498;499/9404-01: Lack of Procedural Guidance for Chiller Operation at Low Loads

Background

The inspectors questioned if the essential cooling water system chillers would be stable when the chiller was loaded to less than 100 tons (i.e., 82 tons post-accident load), without operator action for greater than 30 minutes. The licensee had performed Calculation MC-6429 to model the chiller's evaporator and condenser performance, which indicated that the essential cooling water system accommodated a load of 100 tons at a supply temperature of 42°F without unstable operation. The licensee considered the calculation to have enough margin to support steady-state operation at 82 tons. The licensee was considering whether further procedure guidance on operation at these conditions was needed.

Followup

On August 31, 1994, the licensee revised the Design Basis Document 5V369VB0120, "Chilled Water (CH) System," Revision 2, by issuing Document Change Notice MM-1708. The new revision contained Appendix C.3.2.c, which provided the operator actions and procedural requirements that now address cold essential chilled water conditions less than 42°F, but above 37°F. In addition, the licensee added these provisions to Procedure OPOP02-CH-00001, "Essential Chilled Water System," Revision 7, Section 11.3, "Instructions for Operation Between 37°F and 42°F." In addition, the inspectors interviewed several control room personnel and found that the new instructions had been implemented with no significant problems.

Conclusion

The inspectors concluded that the licensee had implemented satisfactory instructions on essential cooling water chiller operation at low loads.

2.6 (Closed) Inspector Followup Item 498;499/9404-02: Calculation Assumption of 72°F as the Minimum Control Room Temperature not Supported by Procedures

Background

The inspectors noted in a review of Calculation MC-6412 that the licensee's transient minimum heat loads assumed an initial control room minimum temperature of 72°F; however, there was no operational guidance or procedural requirement to maintain this minimum control room temperature.

Followup

The licensee confirmed that 72°F was indeed used as a design assumption for the control room ventilation system. In addition, the licensee indicated that they had not implemented any administrative controls or procedure requirements which addressed this assumption. The inspectors concluded that the licensee had failed to translate the system design into instructions as required by 10 CFR 50, Appendix B, Criterion III, "Design Control." However, the inspectors concluded that this failure was of minor safety significance because a review of component cooling water heat exchanger inlet temperatures indicated that essential chilled water cold (i.e. less than 42°F) conditions did not exist during the cold winter months. Therefore, a combination of cold external temperatures and cold internal control room temperatures would be rare. In addition, the licensee revised Design Basis Document 5V119VB01022 with Document Change Notice MM-1709, dated August 9, 1994, and was in the process of implementing a change to the essential chilled water system's operating procedure, OPOP02-CH-0001, "Essential Chilled Water System," to require that the control room temperature be maintained greater than 72°F, whenever the essential chilled water system was in cold essential chilled water alignment.

Conclusion

The failure to translate the system design into procedures constituted a violation of minor safety significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. The inspectors concluded that the licensee had implemented satisfactory changes to instructions on the minimum control room temperature.

2.7 (Closed) Inspector Followup Item 498;499/9416-02: Spurious Starts of the Standby Diesel Generators

Background

The licensee had experienced several spurious starts of the standby diesel generators. The licensee had previously determined that the cause of these failure was the use of varistors and the installation of relays without surge suppression, which caused voltage spikes that affected the operation of transistors in the start circuitry. In addition, the licensee believed that high control cabinet temperatures and high frequency noise emitted from the direct current power source contributed to the problem. This item was opened to followup on the licensee's continuing efforts to resolve this operational problem. The licensee had a history of licensee event reports (499/94-001, -003 and -005) on this subject which were closed by the inspectors with the closure of this inspector followup item (See Section 3).

Inspector Followup

The inspectors reviewed Condition Report 95-6642, dated June 28, 1995. This condition report documented the licensee's investigation of the unplanned standby diesel generator starts. The investigation included five spurious starts of the standby diesel generators that occurred between May 4 and 20, 1995. Previously, the diesel generator had spuriously started twice in 1993 and six times in 1994. The diesel generator start circuitry could be actuated in the emergency mode or in the test mode. When an emergency mode start signal was received, the relay-based emergency mode start circuitry actuated to energize the master-run relays. However, when a test mode start signal was received, the start signal was processed through fiber optics boards to energize the master-run relays. The licensee did not consider these spurious starts to be safety significant, since the starts were caused by the test circuitry and not the emergency start circuitry.

The inspectors noted that Condition Report 95-6642 described previous corrective actions that had been performed to stop the spurious starts. These corrective actions included adding filters to reduce electrical noise in the diesel generator control cabinets, installation of surge suppression on some relay coils to minimize inductive spiking when the relays were deenergized, installation of control cabinet cooling fans, and replacement of parts.

Condition Report 95-6642 also stated that the licensee had sent 10 fiber optics boards to Failure Prevention & Investigation International to perform failure analysis. The results of the failure analysis showed that some of the power transistors had internal collector-emitter current leakage. The failure analysis also determined that the power transistors were subject to degradation over time due to contamination introduced during their manufacture. The condition report stated that with the ongoing degradation and warm temperatures in the control cabinet, an electrical noise pulse of sufficient size could trigger a spurious start of the standby diesel generator. The licensee concluded that the transistor contamination was the primary source of the starts. Other factors contributing to the spurious starts were temperatures, which contributed to the transistor degradation and electrical noise.

The licensee's future corrective actions include improving transistor parts specifications and installing a cutout switch for the test mode circuit. The licensee also planned to purchase fiber optics boards with transistors with a screening for high collector emitter leakage to eliminate the contamination problem. In addition, the licensee stated that a key lock switch modification would be installed on all six diesel generators by the end of January 1996. The inspectors reviewed the schedule for installing the modifications, dated September 26, 1995. The inspectors noted that two of the Unit 2 diesels would have the key switch modification installed in October 1995.

The inspectors reviewed Condition Report 95-6642-18, "Engineering Report," that described the modification. The planned modification installed a manual key switch in the test mode circuitry to prevent a spurious start signal from operating the master relay. The licensee stated that the test mode circuitry would be disabled while the diesel was in standby and only enabled when a test mode start was desired such as post-maintenance testing. The licensee stated that installing the key switch would not resolve the spurious start signal root cause but would defeat it instead.

Conclusion

The inspectors concluded that the licensee' corrective actions, including the future installation of the key switch in the test mode circuitry, were sufficient to resolve the inspector's concerns.

2.8 (Closed) Licensee Event Report 498/92-018: Pressurizer Safety Valve Setpoints and Main Steam Safety Valve Outside Required Tolerance

Background

During Unit 1's Refueling Outage 1RE04, the licensee discovered that the setpoints of the pressurizer safety valves ranged from +4.3 to -6.7 percent above and below the required setpoints. The setpoints for these valves were set during the previous refueling outage (1RE03). The Technical Specifications required that the setpoint be maintained to +/- 1.0 percent. In Westinghouse Topical Report WCAP-12910, "Pressurizer Safety Valve Set Pressure Shift," dated March 31, 1991, the Westinghouse Owner's Group published corrective actions for setpoint drift and indicated that it was apparently the result of inherent characteristics and the limited capability to determine valve's spindle movement accurately. The licensee had a history of licensee event reports (498/93-011 and -003) on this subject, which were closed by the inspectors with the closure of this licensee event report (See Section 3).

Inspector Followup

As corrective action, the licensee revised the pressurizer safety valve test procedure to require testing the valve setpoints using live steam. This was a recommendation made by Westinghouse and the valve supplier in order to obtain a more accurate set pressure during tests. In addition, the licensee amended the Technical Specifications for the pressurizer safety valves by changing the as-found set pressure tolerance from ±1 percent to ±2 percent, and the main steam safety valves as-found set pressure tolerance from ±1 percent to ±3 percent. The license amendments also stated that the as-left settings should remain within ±1 percent of the set pressure following valve tests.

The inspectors reviewed Test Procedure OPSP11-RC-0013, "Pressurizer Safety Valve Inservice Test," Revision 3, dated September 6, 1995. The inspectors noted that paragraph 1.1 had been revised to specify that the pressurizer safety valve setpoint would be established using live steam. The revised set safety valve setpoint would be established using live steam. The revised set pressure tolerances were also included in this procedure revision. The inspectors also reviewed Test Procedure OPSP11-MS-0001, "Main Steam Safety Valve Inservice Test," Revision 6, dated September 1, 1995, and noted that the licensee had revised the procedure to reflect the amended Technical Specifications as-found and as-left set pressure tolerances. The week after the conclusion of this inspection, the licensee tested 19 of the 20 Unit 2 main steam safety valves and only one of the 19 valves exceeded the ±3 percent as-found set pressure tolerance.

Conclusion

The inspectors concluded that the corrective actions were appropriate and, by increasing the as-found set pressure tolerances, the licensee had decreased the failure rates of the pressurizer safety and main steam safety valves set pressure tests.

2.9 (Closed) NUREG-1517 Paragraph 4.2.2: Contrary to the Administrative Requirements of Operational Procedure OPGP03-ZA-0090, a Field Supervisor Made "Pen and Ink" Changes to a Work Package that Changed the Scope of Work

Background

NUREG-1517, "Report of the South Texas Project Allegations Review Team," identified that the licensee had initiated a Station Problem Report 941460 to document that a "pen and ink" change had broadened the scope of Work Package AN-330313. The NUREG provided the results of a review of allegations from individuals who had contacted Congressional staff members. The changes violated the administrative requirements of Step 3.5.2 of Revision 8 to Procedure OPGP03-ZA-0090, "Work Process Control."

Inspector Followup

The inspectors reviewed Station Problem Report 941460, dated July 25, 1995. The licensee had generated this report to document an occurrence where a "pen and ink" change was made to a work authorization, which increased the scope of the work authorization. The change in the scope of work or intent was not allowed by the licensee's work process program procedure. The problem report resolution recommended development of a lessons-learned training plan. The inspectors reviewed the training records of maintenance personnel dated July 27, 1995, and concluded that lessons-learned training had been completed.

The inspectors also reviewed Maintenance Self-Assessment 95018, "Pen and Ink Change Process," dated August 10, 1995. The assessment stated that 85 preventive maintenance orders and 50 work authorizations had been reviewed and only minor "pen and ink" changes had been made. The licensee did not find any that changed the work scope or intent. The assessment concluded that "pen and ink" changes were a necessary tool for the use of craft supervisors.

The inspectors reviewed the following work authorizations and determined that none of the "pen and ink" changes changed the scope or intent of the work authorization: Work Authorizations 94005431, dated March 13, 1995; 94028581, dated March 28, 1995; 94034089, dated March 13, 1995; 94023116, dated March 24, 1995; 94021289, dated March 24, 1995; and, 94020958, dated March 23, 1995.

The failure to change a work authorization properly was a violation of the licensee's administrative requirements to limit "pen and ink" changes to correction of typographical errors and the like. A change in scope required a revision to the work authorization. The failure to properly change the scope of a work authorization was of minor safety significance in that making such changes was infrequent and the nature of the changes was minor.

Conclusion

The inspectors concluded that the failure to follow the administrative requirements for making a "pen and ink" change constituted a violation of minor safety significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

2.10 (Closed) NUREG-1517 Paragraph 4.6.1: Polar Crane Inspections not in Accordance with Operational Procedure OPMP02-ZG-0003

Background

The NUREG identified a Station Problem Report 920414, dated September 1, 1992, which documented the licensee's failure to perform certain preventive maintenance activities as required on the polar crane.

Inspector Followup

The licensee determined that this station problem report was in error. The licensee performed a complete review of the preventive maintenance records and determined that up until refueling outage (2RE02) in September 14, 1991, all the required preventive maintenance tasks were performed as required. The inspectors noted that Operational Procedure OPMP02-ZG-0003, "Inspection and Maintenance for Crane, Hoist, Monorail Systems and Lifting Devices," Revision 8, Section 6.1.5, had been changed to require preventive maintenance after the outage. The inspectors also verified that the post-outage preventive maintenance for the last outage (1RE05) had been satisfactorily completed.

Conclusion

The inspectors concluded that the preventative maintenance tasks for the polar crane had been satisfactorily performed in accordance with the licensee's operational procedures.

3 IN-OFFICE REVIEW OF LICENSEE EVENT REPORTS (90712)

The licensee event reports listed below were reviewed by the inspectors as part of the reviews made in Sections 2.7 and 2.8 above. The inspectors determined that the reports met the reporting requirement of 10 CFR 50.73, contained an adequate assessment of the subject events, accurately identified the causes of events, identified appropriate corrective actions to the circumstances, and properly considered generic applicability and, therefore, no further regulatory followup was indicated.

- (Closed) Licensee Event Report 498/93-011 on Unit 1: Pressurizer Safety Valve and Main Steam Safety Valve Setpoints Outside Required Tolerance

- (Closed) Licensee Event Report 499/94-001 on Unit 2: Inadvertent Start of Standby Diesel Generator 21

- (Closed) Licensee Event Report 499/94-003 on Unit 2: Inadvertent Test Mode Start of Standby Diesel Generators 21, 22, and 13 Due to Fiber-Optic Board Susceptibility to Noise in Conjunction with Transient DC Spikes

- (Closed) Licensee Event Report 499/94-005 on Unit 2: Inadvertent Test-Mode Start of Standby Diesel Generator 22 During the Cooldown Cycle, Revisions 0 through 3

- (Closed) Licensee Event Report 498/95-003 on Unit 1: Main Steam Safety Valve and Pressurized Safety Valve Setpoints Discovered Outside Required Tolerances

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

T. Asbury, System Engineer
*J. Conly, Licensing Engineer
J. Cottam, Plant Support Systems Supervisor
*R. Fast, Unit 1 Maintenance Manager
*D. Fisher, Consulting Specialist
R. Frazee, System Engineer
R. Graham, Unit Supervisor
T. Harris, System Engineer
W. Harris, Section XI Engineer
*S. Head, Compliance Supervisor
R. Hurt, System Engineer
*M. Johnson, Licensing Specialist
*T. Jordan, Manager Systems Engineering Department
*M. Kanavos, Manager Mechanical/Fluids Systems Division
*M. Lashley, Supervisor Section XI
*M. McBurnett, Manager Nuclear Licensing
L. Merritt, System Engineer
R. Moore, Generation and Distribution Supervisor
W. Moye, System Engineer
J. Pierce, Unit Supervisor
K. Regis, System Engineer
E. Stansel, Senior Consultant
V. Starks, Design Engineer
*S. Thomas, Manager Design Engineering Division
G. Trimble, System Engineer

1.2 NRC Personnel

*J. Keeton, Resident Inspector
D. Loveless, Senior Resident Inspector

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

*Denotes personnel that attended the exit meeting.

2 EXIT MEETING

An exit meeting was conducted on September 28, 1995. During this meeting, the inspectors reviewed the scope and findings of the inspection. The licensee acknowledged the inspection findings as they were presented. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.