APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-498/92-33
50-499/92-33

Operating Licenses: NPF-76
NPF-80

Licensee: Houston Lighting and Power Company
P.O. Box 1770
Houston, Texas 77251

Facility Name: South Texas Project Electric Generating Station

Inspection At: Matagorda County, Texas

Inspection Conducted: November 16-20 and December 14-17, 1992

Inspector: L. D. Gilbert, Reactor Inspector, Maintenance Section
Division of Reactor Safety

Approved: T. F. Stetka 1/4/93
T. F. Stetka, Chief, Maintenance Section Date
Division of Reactor Safety

Inspection Summary

Areas Inspected: Routine, announced inspection of erosion/corrosion monitoring activities.

Results:

- The licensee has developed a good erosion/corrosion program.
- The administrative procedures clearly defined responsibilities for the erosion/corrosion program.
- Personnel effectively implemented the erosion/corrosion program.
- Results to date indicate that no significant erosion/corrosion degradation has occurred in carbon steel piping systems.

Summary of Inspection Findings:

- No inspection findings were opened or closed.

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

During this inspection period, Unit 1 was in the fourth refueling outage.

1.2 Unit 2

During this inspection period, Unit 2 was operating.

2 EXAMINATION OF EROSION/CORROSION MONITORING PROGRAMS (49001)

The objectives of this inspection were to ascertain licensee commitments and procedures that were developed and implemented to address a long-term erosion/corrosion monitoring program in accordance with Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning."

2.1 Discussion

The inspector reviewed the licensee's response to Generic Letter 89-08 which was documented in three letters dated July 24 and October 2, 1989, and February 15, 1991. The licensee notified the NRC in the letter dated February 15, 1991, that a formalized long-term erosion/corrosion program, equivalent to the Nuclear Utility Management and Resourses Council guidelines referenced in Generic Letter 89-08, had been implemented which assured the structural integrity of carbon steel piping systems carrying high-energy water in single-phase flow and steam in two-phase flow.

2.1.1 Program

The inspector verified that a formalized program was in place regarding erosion/corrosion monitoring of piping system components. The responsibilities, interfaces, and requirements for administration of the erosion/corrosion program at the South Texas Project Electric Generating Station were defined in Interdepartmental Procedure IP-3.32Q, "Erosion/Corrosion Program," Revision 1. The procedure specified that the Design Engineering Department was responsible for developing and maintaining the erosion/corrosion program. The procedure also specified responsibilities for providing operating information, chemistry history, and thickness measurement data to design engineering. In addition, the procedure addressed quality assurance audit and surveillance responsibilities, as well as, the responsibility of maintenance personnel to report to design engineering any erosion/corrosion related degradation or failures of components identified during maintenance activities. The administrative controls of the erosion/corrosion program within the Design Engineering Department were described in Operations Engineering Procedure OEP-10.08Q, "Erosion/Corrosion Program," Revision 0. The procedure specified that the engineering input and evaluations were the responsibility of the Pipe Stress/Support Group and the examination program and coordination were the responsibility of the Inservice Inspection Group of design engineering.

The inspector reviewed the engineering evaluation performed by the licensee which identified the following piping systems as being potentially susceptible to erosion/corrosion: auxiliary feedwater; condensate; extraction steam, feedwater; heater drip; heater vent; liquid waste processing; main steam, steam generator blowdown; and turbine gland seal. Design engineering selected an initial sample of 59 components in Unit 1 for examination during the first refueling outage in 1989 to establish baseline thickness measurements and measured wear rates on components representative of those areas in the piping systems predicted to be most susceptible to erosion/corrosion. The same components examined in Unit 1 were examined in Unit 2 during the first refueling outage in 1990. In addition, 19 other components were examined in Unit 2 based on industry experience and additional component selection to meet program expansion requirements when wall thinning was identified in other system components. An example of industry experience was the problem at the Catawba Unit 2 plant, reported in NRC Information Notice 92-07, involving rapid flow-induced erosion/corrosion of the auxiliary feedwater piping. In response to the information notice and the subsequently identified thin wall component, the licensee's immediate action included a review of the auxiliary feedwater system and examination of a piping component in each unit with no degradation predicted or measured. Additional components in the auxiliary feedwater system were selected and examined as part of a long-term action plan. A thin area was identified on the side wall of Elbow AF-1010-16E in Unit 1. The elbow was removed from the piping system for metallurgical evaluation and a new elbow installed. The metallurgical evaluation report dated November 23, 1992, concluded that the wall thinning occurred during original manufacturing and there was no evidence of erosion/corrosion occurring inside the pipe. To date, nine components in the auxiliary feedwater piping have been examined and no other degradation of the system piping was identified. The erosion/corrosion program also identified degraded components in other piping systems. However, the components were not degraded significantly by erosion/corrosion but as the result of installation or fabrication errors. For instance, the initial examination of a heater drip piping system identified a thin wall condition on a component which was documented in RFA-91-0433 for engineering evaluation. Engineering determined, by thickness measurements and markings on the components, that a Schedule 40 fitting was installed in three of the four heater drain trains where a Schedule 60 fitting was required by design. The three degraded components were replaced.

The inspector selected four of the above piping systems examined during 1991 for review of the database used in the erosion/corrosion computer analysis for both units. The computer analysis programs used the EPRI developed CHEC and CHECMATE programs for single phase and two phase flow, respectively. The systems selected were the extraction steam, feedwater, heater drip, and steam generator blowdown systems. For each of the systems, the inspector compared the engineering input data and plant conditions to the database in the computer program for a segment of piping for both units. The database parameters reviewed included the pipe size, schedule and length, component material and geometry factors, and operating conditions regarding flow rate, moisture content, water chemistry, temperature, pressure, and hours of operation. For the components selected and parameters reviewed, the database in the computer programs was consistent with the parameters specified by engineering, operations, and chemistry. The basis for the engineering input parameters was derived from, and in agreement with, the piping isometric drawings, the basic flow and heat balance diagrams, the piping design specification, and the CHEC and CHECMATE User's Manuals. The inspector was informed that a field walkdown had also been performed on portions of the extraction steam, feedwater, and heater drip systems in both units to verify that the design drawings accurately depicted the plant conditions. The walkdown was documented in a memorandum dated April 23, 1992. Results of the walkdown indicated that the design drawings provided a good basis for constructing the erosion/corrosion models.

2.1.2 Examination Plan

The inspector reviewed the 1992 Erosion/Corrosion Examination Plan for the fourth refueling outage of Unit 1 and the 1991 Erosion/Corrosion Examination Plan for the second refueling outage of Unit 2. The examination plans provided an excellent description of the components and additional areas on adjacent piping located upstream or downstream of the components which were to be included in the examinations. The examination plans also specified the pipe size and nominal thickness, grid size and spacing, examination method, the acceptable thickness, and the reference to engineering dispositions for components with a measured thickness below the acceptable thickness (specified as the manufacturing minimum thickness). Measured thickness values below the acceptable thickness were identified to design engineering for a case-by-case evaluation and disposition. The inspector reviewed the previous outage summary reports for both units. The reports listed 102 components examined in Unit 1 during the third refueling outage and 106 components examined in Unit 2 during the second refueling outage. For each unit, the inspector selected two components from the extraction steam, feedwater, heater drip, and steam generator blowdown systems and reviewed the thickness measurements and the CHEC and CHECMATE analysis for each. The inspector was informed that the band method was used to determine the thickness and wear rate values input as parameters to the CHEC and CHECMATE programs. The values used for the current component thickness and wear rates were found to be in agreement with the measured thickness reading. For those components with a thickness less than the specified acceptable thickness, the inspector verified that the results had been evaluated and satisfactorily dispositioned by design engineering. The inspector was informed that, although the analysis permitted a reduced examination frequency, the components were being examined each refueling outage to provide a good database for point-to-point thickness measurements and better component life predictions.

In addition, the inspector witnessed the measuring of component thicknesses on Component ES-1005-02V in the Unit 1 extraction steam piping system. The ultrasonic thickness measurements were taken at each grid intersection and recorded in a data logger using the same alpha-numeric reference locations permanently marked on the component. The grid layout, equipment calibration, thickness measurements, and data acquisition were performed consistent with the approved examination plan and Procedure NDEP 4.2, "Nondestructive Examination Procedure," Revision 2. The inspector verified that the personnel conducting the thickness measurements were certified for the ultrasonic method and the test instruments were within the calibration interval. The inspector also noted that the piping isometric drawing was consistent with the piping and components installed in the plant.

2.2 Conclusions

The licensee has developed a good program for the detection of component degradation resulting from erosion/corrosion that addresses the concerns identified in Generic Letter 89-08. The administrative procedures clearly defined responsibilities for developing, maintaining, and implementing the erosion/corrosion program. Personnel were knowledgeable of the computer programs for predicting erosion/corrosion-induced pipe wall thinning and effectively implemented the erosion/corrosion program. The results of the piping examinations performed to date indicate that wear rates are generally low and no significant erosion/corrosion wear has occurred in the carbon steel piping systems.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

*B. Auguillard, Senior Development Analyst
*C. Ayala, Supervising Engineer, Licensing
*R. Dally-Piggett, Engineering Specialist, Licensing
*D. Denver, General Manager, Nuclear Assurance
*D. Hall, Group Vice President, Nuclear
*J. Johnson, Supervisor, Quality Assurance
*W. Jump, General Manager, Licensing
*M. Lashley, Staff Engineer
*D. Leazar, Manager, Plant Engineering
*G. Parkey, Plant Manager
S. Patel, Supervisory Engineer
*S. Rosen, Vice President, Nuclear Engineering
A. Sharon, Responsible Engineer

1.2 NRC Personnel

*J. I. Tapia, Senior Resident Inspector

*Denotes personnel that attended the exit meeting. In addition to the personnel listed, the inspector contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on December 17, 1992. During this meeting, the inspector reviewed the scope and findings of the report. The licensee did not identify as proprietary, any information provided to, or reviewed by the inspector.