UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report No.: 50-261/92-13

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket No.: 50-261 License No.: DPR-23

Facility Name: H. B. Robinson

Inspection Conducted: April 27 - May 1, 1992

Inspector: _____ 6/11/92
for Nick Economos Date Signed

Approved by: _____ 6/11/92
Jerome Blake, Chief Date Signed
Materials and Processes Section
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope:

This routine, unannounced inspection was conducted in the areas of inservice inspection work activities, and maintenance.

Results:

Significant programmatic weaknesses were identified in the areas of maintenance and they are summarized below. Examination of S/G shell weld No. 5 (upper girth weld), confirmed the presence of recordable indications identified in previous inspections. These indications are undergoing analysis to determine possible changes from previous examinations and code acceptability. Eddy Current (EC) examination of S/G tubes disclosed no evidence of significant tube wall degradation through corrosion, one tube was plugged however because an obstruction precluded its inspection. The erosion corrosion program is directed by one individual who uses engineering judgement to determine inspection schedules,

component replacement and material selection. There was no evidence of corporate involvement in this program. The licensee indicated that plans are underway to correct this problem. Pitting corrosion has degraded the service water piping at the intake structure to the extent that it is being replaced during this outage. This condition is mostly the result of neglect i.e., there have been no maintenance inspections to monitor the OD surface condition of these pipes and take appropriate preventative measures as necessary. The feedwater nozzle reducer to pipe welds have been monitored/examined during refueling outages since S/G replacement in 1984. No evidence of cracking has been detected.

In the areas inspected deviations or violations were not identified.

Report Details

1. Persons Contacted

Licensee Employees

*R. Barnett, Manager Outages and Mod
*S. Barrett, Senior Specialist, NAD
E. Black, Supervisor, NDE Services
R. Chambers, General Plant Manager
R. Cooper, Senior Engineer Technical Support
*C. Dietz, Vice President, Robinson Nuclear Power Division
*W. Farmer, Manager, Engineering Programs
C. Griffin, Materials Engineer Nuclear Engineering Department
*J. Harrison, Regulatory Compliance Manager
J. Latimer, Welding Engineer, Technical Support
D. Meleg, Level III Eddy Current Examiner
*C. Osman, Principal NDE Specialist Technical Services Department
*M. Page, Manager, Technical Support
D. Weber, Senior Inservice Inspection Specialist

Other licensee employees contacted during this inspection included engineers, technicians, and office personnel.

NRC Resident Inspectors

L. W. Garner, Senior Resident Inspector

*Attended Exit Interview

2. Inservice Inspection (73753) Unit - 2

This inservice examination effort was the first such activity of the first period in the current (third) interval. The governing code for this interval is the ASME Code, Section XI 1986 Edition with no addenda. Volumetric and surface examinations scheduled for this outage were relatively few in number and as such had been completed at the time of this inspection. Activities in progress included confirmatory UT examinations of weld No. 5 in S/G(s) A&C, maintenance (pipe replacement) in the service water system and erosion corrosion inspections in the Heater Drain system. These activities were observed and will be discussed in the following paragraphs.

a. Confirmatory Ultrasonic Examination of Steam Generator (S/G), A&C Weld No. 5

By review of inspection reports, evaluation documents and through discussions with cognizant licensee personnel, the inspector ascertained that weld No. 5 in S/G "B" was examined during the 1990 refueling outage which resulted in the detection of three low amplitude reflectors. These reflectors were located in the base metal, adjacent to the weld in the inside diameter (ID), side of the subject weld. Because their amplitude was less than 50 percent of reference, the indications were not sized. Because other utilities had examined and had found corrosion fatigue cracking in the same weld, the licensee decided to UT examine this weld in S/g(s) "A" and "C". Results of these inspections showed that numerous indications were identified at or near the root of the weld, both in the weld metal and the base metal adjacent to the weld. Some of these indications exceeded ASME Section XI, IWB-3500 criteria. Of these indications, surface flaws 0.3 inches deep in S/G "A" and 0.47 inches deep in S/G "C" were considered as the bounding flaws, based on sizing dimensions obtained from exams with 45° shear wave transducers.

UT with a 60° transducer revealed apparent flaws to 0.79 inches deep in steam generator A and, to 0.53 inches deep in steam generator C. However, CP&L determined that examinations by the 45° beam were more reliable and were used for all official ISI assessments. UT by both methods was shown to provide conservative estimates of crack depth and length. Flaw specific analyses for the limiting flaws conducted by Structural Integrity Associates Inc., concluded that both flaws would be acceptable for 18 months' operation, even using the as-UT-called length and depth dimensions. These dimensions were shown to be conservative by CP&L based upon comparison with calibration block results and internal MT results. All of the observed flaws were short and oriented essentially circumferentially. The size and location of the indications suggests that they are fabrication defects.

During the timeframe documented by the present report, the inspector ascertained that weld No. 5 in S/G(s) "A" and "C" was ultrasonically examined by Siemens Nuclear Power Services Inc. (SNPS) utilizing a mechanical/semi-automated UT procedure (P-Scan) written to comply to the applicable code. The weld was examined with 45° and 60° shear wave transducers. As stated above the examination identified previously observed recordable indications. Because previous examinations were performed manually, exact correlation of data obtained by the P-Scan was difficult to attain. In order to remedy this situation the licensee conducted a confirmatory UT examination of certain indications in S/G(s) A&C. The examinations, which were witnessed by the inspector, were extremely difficult to perform because of the proximity of the weld to the bioshield wall which surrounds the S/Gs. A total of seven indications were selected for this effort in S/G in "A" and two in S/G "C". Of these the CP&L examiners could not duplicate the dimensions report by manual examination during the 1990 outage. At the close of this inspection the aforementioned data was undergoing evaluation to determine if any further action was necessary. This matter will be revisited on a routine basis during a future inspection.

b. Steam Generator (S/G) Feedwater Nozzle Inspections

Recently cracking of piping at the S/G Feedwater nozzle was identified in a W PWR plant. The cracking was attributed to thermally induced fatigue caused by introducing relatively cold feedwater into the main feedwater pipe upstream of the S/G. This cracking problem was identified in 1979 and NRC Bulletin 79-13 was issued to require inspection and replacement of defective feedwater piping components.

Because of currently identified cracking at another utility, the inspector discussed the status of inspection for similar piping components at Robinson. Through these discussions the inspector ascertained that the Robinson S/G feedwater nozzles have thermal sleeves which were installed in 1984 during the S/G replacement. In addition, the inspector ascertained that the nozzle safe-end to pipe welds were examined during the 1986 outage and subsequent outages including the 1990 outage at which time only one nozzle was examined. These examinations identified a low amplitude (40% DAC), root geometry condition in S/G "C" feedwater nozzle weld No. 1. UT records showed the indication was detected with the 45° shear wave transducer while scanning in the number five (5) direction or going away from the S/G. The indication was described as intermittent with an overall length of about 11 inches. In response to the inspector's expressed concern and request for an examination of this weld, the licensee examined the first two welds, upstream of the nozzle, measuring 18" and 16" in diameter. The examination was performed in accordance with UT procedure SP-1089, Rev. 0. The welds were scanned with 0° and 45° shear transducers from both sides of the joint including ½ inches of the adjacent base metal. The examination revealed root geometry below recording levels which suggests that no changes have taken place since the previous inspection. Additional examinations were performed following the close of this inspection and are documented in Report 92-14.

c. Eddy Current Examination (ET)

At the time of the inspection, ET inspection of steam generator (S/G) tubes had been completed. The inspector reviewed and discussed with licensee personnel the inspection plan and inspection results for the current outage. The following summarizes the inspection plan and inspection results:

The inspection plan called for the examination of 20 percent of the tubes per S/G with bobbin probe. This population included, previously inspected tubes with known indications, or three percent of the total and, an additional 17 percent of randomly selected tubes that previous examinations showed them to be free of indications. Motorized pancake coil examinations were used on bobbin indications requiring resolution. Two of the governing procedures used to perform the examination were as follows:

ROB-410-004, Rev. 45	Eddy Current Examination of Nonferromagnetic S/G Tubing Using MIZ-18 Equipment
ROB-410-005, Rev. 3	Evaluation of Westinghouse S/G Tubing

Referenced Code and Regulatory Requirements included, ASME Code Section XI 1986 Edition with no Addenda, Regulatory Guide 1.83, Rev. 1, 1975, Code Case N-401-1 and Code Interpretation XI-1-83-18. The examination was conducted by ABB-Combustion Engineering. The examination resulted in one tube (R1-C29), being plugged because a localized obstruction (dent), stopped the probe from passing through the tube. By review of records the inspectors ascertained that the licensee's Level III EC examiner maintained daily contact with the contractor and observed data acquisition and analysis while the activity was in progress. The most recent QA audit of this vendor ABB/CE was performed on December 13, 1991 by Nuclear Process Issues Committee (NUPIC). The licensee has committed to conduct similar audits on a tri-annual basis.

d. Review and Evaluation of ISI Records (73755)

Records of completed examinations, and associated QA documents were reviewed for completeness, accuracy and to evaluate the extent of the examination as required by the applicable code. The records and supporting documents reviewed were as follows:

Figure	Weld/Component	Sketch	Description
C5.11 and .12	13 and ½ of LS	CPL-218	Pipe to Ell
	One recordable indication identified		
C5.21 and .22	10 and 2½ of LS	CPL-240	Pipe to ELL
	2, 5 and 2½ of LS	CPL-239	Pipe to Valve and "T" to Valve

Weld No. 2: root geometry, intermittent observed with 60° shear transducer. Examination limited to one side of the weld because of valve configuration.

Weld No. 5: Condition observed was same as in Weld No. 2 above, on the "T" side of the joint.

C5.21 and .22	6 and 2½ T of LS	CPL-239	T to Pipe
	7 and 2½ T of LS	CPL-239	and Pipe to Flange

Examined on one side only because of configuration, root geometry verified in amplitude and length (intermittent).

Certifications of equipment and material reviewed were as follows:

Transducers

KB-10175	½" diam.	0°
G-20839	¼" diam.	45°
B-27400	¼" diam.	60°

Instrument

USK-7 (KBI)	27276-3702
USK-7 (KBI)	27276-3789
USK-7 (KBI)	27276-3784

Couplant

Ultragel II	092041

Within the areas examined violations or deviations were not identified.

3. Erosion/Corrosion - Induced Pipe Wall Thinning Program.

In response to Generic Letter 89-08 requirements and the licensee's response dated July 21, 1989 the inspector observed a scheduled examination on component, No. 1HD24. This was a schedule 40, 12x8 reducer in line number 8-HD-233 of the Heater Drain system. The observation included grid layout, instrument calibration, data acquisition using a Panametrics 26DL Plus unit and downloading. Nominal material thickness was identified a 0.406 inches, with a minimum of 0.346 inches. Following this field observation, the inspector reviewed the controlling document, identified as Maintenance Instruction (MI) No. 010-1, Erosion/Corrosion Control Program dated June 10, 1987 and discussed with the cognizant engineer, administrative controls including: use of EPRI's codes Chec-NDE and Checmate, corporate involvement in terms of design engineering support, and program management. Following this discussion, the inspector ascertained that the licensee has committed at best, only a minimum amount of resources in this program. For example, there is no objective evidence of corporate involvement in the Robinson Erosion/Corrosion (E/C), program in terms of an approved corporate manual to address, programmatic direction, decision making responsibilities, component replacement, data management etc. The program is presently directed by one engineer, on a part time basis, who decides what components are inspected, when they are replaced and what types of replacement material is to be used. There are no program driven acceptance criteria based on projected wear rates or trending of systems and specific components. The engineer relies heavily on personal experience and knowledge of system performance, as guidance to generate inspection scope(s) during outages. Some systems have been modeled after a Checmate Computer Code, but predictions made by this program have been so increditably off the mark that the engineer has lost confidence in the system. Examples presented to support this position were, (1) Component between feedwater pump A to S/G "A", Checmate predicted failure 43K hours ago but U/T thickness measurements show it to be within code allowable limits, (2) component between heater drain "B" and heater drain tank "B", Checmate predicted failure 134,015. hours ago but the component still meets code allowable limits. This poor reliability has diminished confidence in this code to the point that it is not utilized or relied upon as a predictive tool.

The inspector ascertained that the heater drain lines have experienced the greatest amount of wear. This system contains mostly carbon steel piping except for lines No. 5 and No. 6 which have been replaced with C Mo, low alloy material. Smaller lines i.e. one inch or less have been replaced with stainless steel material. The inspector expressed his concerns over the lack of corporate involvement and organization in this program prior to and at the exit interview. Management concurred with the inspector's observations and indicate that although some steps have been taken to phase in corporate involvement into the program, additional efforts will be made to expedite this process. The inspector indicated that Inspector Followup Item (IFI) 92-13-01, Erosion/Corrosion Program Improvement, would be identified for tracking purposes.

4. Licensee Action on Previous Inspection Findings

(Open) IFI 261/92-09-02, Corrosion on Exterior Surfaces of Service Water Lines at the Intake Structure

This item was opened to document concern over the pitting corrosion attack identified on the exterior surfaces of the downcomers connecting the pumps to the header at the Intake Service Water Structure. Since the subject inspection, the licensee evaluated the extent of the damage and determined that the components in question (downcomers), should be replaced during this outage. The governing code of the affected piping is the American Water Works Association (AWWA). The replacement material is the same as that now in place, A139 Grade B, except that nominal wall thickness has been increased from 0.125 inches to 0.188 inches. No decision has been reached on the external protective coating to be applied. The 31 inch header is made of the same material and has the same nominal wall thickness as the downcomer replacement material. The inspectors performed a visual inspection to observe and assess the heretofore described corrosive attack on the downcomers and on the 31 inch header. By this inspection, the inspector verified the concern documented in the aforementioned IFI. The inspector concentrated his efforts on an area of about 20 to 30 square inches located on the east side of the header. This area is currently being investigated by the licensee to assess the extent of the damage and to determine if the header is acceptable for continued service without repair. By observation and through discussions the inspector ascertained that the licensee has no preventive maintenance program to monitor the condition of piping exposed to the environment, as in this type application. Therefore it would appear that the lack of preventive maintenance and neglect permitted the corrosive attack to go unchecked and cause the degraded condition which rendered the downcomers unacceptable for continued service. The replacement activity, the evaluation of the Header and implementation will be revisited on a future inspection on a routine basis. This item will remain open until this review is completed.

5. Exit Interview

The inspection scope and results were summarized on May 1, 1992, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.