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

AUG 31 1989

Report Nos.: 50-369/89-26 and 50-370/89-26

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-369 and 50-370 License Nos.: NPF-9 and NPF-17

Facility Name: McGuire 1 and 2

Inspection Conducted: August 7-11, 1989

Inspector: Thomas R Decker for 8/30/89
S. S. Adamovitz Date Signed

Approved by: Thomas R Decker 8/30/89
T. R. Decker, Chief Date Signed
Radiological Effluents and Chemistry Section
Emergency Preparedness and Radiological
Protection Branch
Division of Radiation Safety and Safeguards

SUMMARY

Scope:

This routine, unannounced inspection was conducted in the areas of plant chemistry, previously identified items, and status of the steam generator blowdown recycle system.

Results:

In the areas inspected, violations or deviations were not identified.

The licensee had effectively maintained primary chemistry within Technical Specification requirements and secondary chemistry within the limits recommended by the Steam Generators' Owners' Group (Paragraphs 3.a and 3.b).

One unresolved item (Paragraph 2.b) remained open concerning the radioiodine and particulate sampling requirements of NUREG 0737 IIF.1-2. Licensee management verbally committed to install the heat tracing to outside sampling lines by October 31, 1989.

The steam generator blowdown recycle (BB) system and corrective actions for the possible unmonitored release pathway were discussed (Paragraph 5).

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REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *N. Atherton, Production Specialist, Compliance
   G. Barker, Supervising Scientist, Chemistry
   *M. Bridges, General Supervisor, Chemistry
   S. Copp, Planning and Maintenance Manager
   K. Davis, Nuclear Production Engineer
   *D. Ethington, Nuclear Production Engineer
   *J. Foster, Radiation Protection Manager
   M. Funderburke, Chemistry Manager
   *L. Haynes, Scientist, Radiation Protection
   D. Mayes, Maintenance Engineer
   *T. McConnell, Station Manager
   D. Mei, Associate Engineer
   R. Michael, Chemistry Manager
   *M. Rains, Engineering Supervisor, Projects
   O. Reid, Supervisor, Chemistry
   C. Robinson, Engineering Supervisor
   *R. Sharpe, Compliance Manager
   W. Smith, Production Specialist III
   C. Trezise, Nuclear Production Engineer
   W. White, Nuclear Production Engineer
   C. Whitten, Nuclear Chemistry Specialist

   NRC Resident Inspectors

   *T. Cooper
   K. Van Doorn

   *Attended exit interview

2. Licensee Action on Previous Enforcement Matters (92702)

   a. (Closed) Violation (VIO) 50-369, 370/87-01-01: Failure to conduct adequate Fe-55 analysis for liquid effluent release measurements. The inspector discussed Fe-55 analysis with cognizant licensee representatives. The Duke Power Applied Science Center began performing Fe-55 analyses for McGuire during August 1988, and the licensee's corporate office had been supplying the laboratory with Fe-55 crosscheck samples. Per discussions with corporate personnel, analytical results for the last three crosscheck samples supplied in March and June 1989 were within 16 percent, 6 percent and 5 percent respectively of known values. Additionally, the licensee had analyzed an NRC crosscheck sample during January 1989, and Fe-55 results were in agreement with known values. This item is considered closed.

b. (Cpen) Unresolved Item (URI) 50-369, 370/87-13-01: Review the radioiodine and particulate sampling requirements of NUREG-0737 IIF.1-2 and determine if sampling requirements are met. The inspector and a licensee representative examined a remote sampling station that would be used to sample the unit vent stack during post loss of coolant accident (LOCA) conditions. The remote sampler was constructed with the same components as the original sampling train. The remote train consisted of a portable vacuum pump, flow meter and vacuum gauge with quick disconnects for the particulate filter, charcoal cartridge or gas bomb sample containers. The inspector also examined the procedure HP/0/B/1009/06, "Procedure for Quantifying High Level Radioactivity Releases during Accident Conditions," dated March 24, 1989. The "Limits and Precautions" section of the procedure identified the station's Radiation Protection Manager/designee as having the authority to provide appropriate surveillance and control of people collecting samples, and referenced the use of radiation control practices including portable shielding for sample collection. The procedure also identified the use of a shielded container to transport the samples to the laboratory in order to minimize dose. Per discussions with the licensee, the inspector determined that the addition of heat tracing to exterior sampling lines had not been completed. The original station modifications MG-1-1623 and MG-2-0588 were identified in 1985, and covered the installation of the remote particulate and iodine grab sampling stations and also the addition of heat tracing to sampling lines.

During the exit meeting conducted August 11, 1989, the inspector requested that a firm date be established for installation of the heat tracing. The station's manager committed to a completion date of October 31, 1989. As indicated in a previous inspection report (50-369, 370/89-12), Nuclear Reactor Regulation (NRR) staff were evaluating the licensee's sampling system. Since NRR had not completed the evaluation at the time of this inspection, this item remains open.

c. (Closed) VIO 50-369, 370/89-12-01: Failure to include a description of unplanned releases in the Semiannual Effluent Release Reports as required by Technical Specification (TS) 6.9.1.7. The licensee provided amended reports dated June 20, 1989, which included descriptions of the abnormal releases. The inspector reviewed the amended reports and concluded that the descriptions were adequate. Additionally, the amended report for July-December 1988 corrected the amount of liquid activity released as requested by the inspector during the April 1988 inspection. This item is considered closed.

3. Plant Chemistry (84750)

At the time of this inspection, McGuire Unit 1 was currently operating at 100 percent power and Unit 2 was in a planned refueling outage which began July 5, 1989, after having completed its fifth fuel cycle. Unit 1 was in its sixth fuel cycle after a planned refueling outage which lasted from October 1988 to January 1989. Unit 1 had also experienced shutdown from March 8 to April 1989, due to a tube rupture in Steam Generator B. The inspector reviewed the plant chemistry controls and operational controls affecting plant chemistry during 1988 and 1989.

a. Review of Units 1 and 2 Reactor Coolant Chemistry Controls

(1) TS 3/4.4.7 requires that the concentrations of dissolved oxygen, chloride, and fluoride in the reactor coolant systems be maintained below 0.10 parts per million (ppm), 0.15 ppm, and 0.15 ppm respectively at steady-state operations. The inspector reviewed 1988 and 1989 data for these chemistry variables and determined that these parameters were maintained well below TS limits in both units. Typical values for dissolved oxygen, chloride and fluoride when the units were at 100 percent power were less than 5 parts per billion (ppb), less than 25 ppb, and less than 25 ppb, respectively. During March 1989, a table top ion chromatograph replaced previous laboratory methods for chloride and fluoride analyses in the primary chemistry laboratory and the lower limit of detection decreased to approximately 1 ppb for these ions. Typical primary coolant values for chloride and fluoride with the ion chromatograph were 2 to 6 ppb.

(2) The licensee had performed induced crud bursts for both units during past outages. The crud bursts were accomplished by the addition of hydrogen peroxide to the reactor coolant systems and were designed to reduce out-of-core radiation/contamination levels by solubilizing fission and activation products deposited on out-of-core metal surfaces. Approximately two years ago, the licensee performed a "mid-plane" crud burst on Unit 1 which was performed by draining the reactor coolant to mid-plane and cycling the water with the residual heat removal (RHR) pumps. The licensee determined that the mid-plane crud burst was not as effective as a "water solid" crud burst where the reactor coolant sytsem (RCS) was filled and a reactor cooling pump circulated the water. After the one use of the mid-plane procedure, the licensee opted to perform all water solid crud bursts. Crud burst data for past outages are presented in the

table below:

MCGUIRE CRUD BURST DATA

Date	Co-58 (Curies)	Co-60 (Curies)
Unit 1		
September 5-10, 1987	80	2.3
October 14-17, 1988	179	3.8
Unit 2		
May 2-10, 1987	942	67
May 28 - June 1, 1988	589	11.7
July 5-12, 1989	492	11.6

(3) The licensee performed the following preventive actions to reduce primary side stress corrosion cracking (PSSCC) of the steam generator tubes:

(a) Shot peening was performed for steam generator tubes on the hot leg side in 1986 for Unit 1 and in 1987 for Unit 2. The licensee was also performing shot peening of the cold leg side for Unit 2 during the current outage and planned to performed the same for Unit 1 during the 1990 refueling outage. Shot peening of the tubes was performed to reduce or eliminate residual stresses remaining from steam generator construction. Additionally, U-bend stress relief in the Units 1 and 2 steam generators was performed in 1988.

(b) The licensee had adopted an optimum range of 25 to 35 cc/kg for hydrogen overpressure in the RCS. Facility requirements limited hydrogen overpressure to less than 50 cc/kg and this reduction was implemented to minimize the possibility that PSSCC might be affected by hydrogen. The inspector reviewed graphed hydrogen data covering the past 24 months. Units 1 and 2 hydrogen overpressure numbers typically ranged from 25 to 40 cc/kg at 100 percent power. The inspector also examined selected 1989 raw data for both units. Unit 1 hydrogen overpressure ranged from 30 to 35 cc/kg and Unit 2 from 30 to 45 cc/kg.

(c) The licensee had incorporated the Electric Power Research Institute (EPRI) guidelines for a coordinated boron/lithium program with a constant pH of approximately 6.9 at 300°C. At the beginning of cycle, lithium is maintained from 1.9 ppm to 2.2 ppm at 1,200 ppm boron. By the end of cycle, lithium concentrations have decreased to 0.2 ppm to

0.5 ppm at 0 ppm boron. The licensee indicated that the pH on Unit 1 was currently 6.6 and the pH on Unit 2 was 6.8 before the unit came down for the outage. At this time, the plant was not considering a program to increase lithium concentrations above the upper limit of 2.2 ppm. Higher lithium concentrations with the correspondingly higher pH have been predicted to lower primary system dose rates. However, there are potential concerns for increased fuel corrosion and PSSCC of steam generator tubes with the increased lithium concentrations in the primary system. Tests were currently being conducted at Millstone to determine the effect of higher lithium concentrations on primary systems and the licensee was waiting for these results before considering a change to their current program.

b. Review of Units 1 and 2 Secondary Chemistry Controls and System Operations

(1) Main Condenser

For Unit 1, the licensee had experienced one condenser tube leak during the past year which occurred during July 1989. The leak was determined to be from one tube in the upper part of the 1B waterbox and was repaired. For Unit 2, the licensee had experienced four tube leaks during the past 12 months. The leaks occurred on October 31, 1988; November 6, 1988; January 27, 1989; and February 13, 1989. All the leaks occurred in the 2A1 waterbox and were caused by a steam dump into the north side of the 2A1 hotwell section. The steam dump was caused by a leaking valve and as the leaking condenser tubes were plugged, the continued steam leak led to steam erosion in the surrounding tubes. The valve was to be fixed during the current outage to prevent any further condenser leaks.

Above the waterline air inleakage into the condenser was routinely monitored and the licensee indicated that historically inleakage ranged from 11 to 13 SCFM. Unit 1's inleakage was currently slightly below that level with inleakage of 6 to 8 SCFM and Unit 2's inleakage was 12 SCFM prior to the current outage. The inspector also reviewed 1988 and 1989 graphed dissolved oxygen levels in the condenser hotwell. Typical values at 100 percent power ranged from 1 to 2 ppb for both units.

(2) Condensate Cleanup Systems

McGuire, like Catawba, had experienced similar problems with the original condensate polishing demineralizer (CPD) filter elements which allowed large flow-through but permitted resin leakage into the secondary system. By 1987, McGuire had completed installation of a new design filter tube which was a sintered metal element (Pall Porous Metal Membrane). The new elements corrected the leakage of resin fines but maintained problems with iron fouling and precoat washdown problems. The problems resulted in high differential pressure across the CPDs and the inability to get 30 precoats before the bundles had to be sent offsite for cleaning. The licensee determined that the areas of the elements affected by iron fouling would not precoat until after the element has been chemically cleaned by an offsite vendor. Precoat washdown problems were caused by turbulence of the incoming water. The licensee initiated corrective actions which included adding a flocculating agent to the precoat, reducing the turbulence of the incoming water, and checking the turbidity of the supernate. Currently the plant was getting approximately 10 to 15 precoats before chemical cleaning was required of the elements. The plant had contracted with another vendor to perform the element cleaning and was considering the use of disposable elements which could be discarded after a designated number of precoats. The licensee had also investigated the possibility of inhouse cleaning but the estimated cost for equipment and process implementation was considered excessive. The licensee did not use the condensate polishers for full flow cleaning of the condensate. Since 1984, approximately 10 percent of the condensate and 100 percent of the steam generator blowdown were routed through the polishers. For 1988 and 1989, typical values for cation conductivity of the polisher effluent were 0.11 umho/cm to 0.12 umho/cm.

(3) Steam Generators

The inspector examined 1988 and 1989 cation conductivity data for both units' steam generators. The cation conductivity values ranged from 0.16 umho/cm to 0.24 umho/cm. These low values resulted from a combination of clean feedwater and high steam generator blowdown rates which effectively removed contaminants. For both units, steam generator blow down rates were maintained at approximatley 99 gallons per minute (gpm) per steam generator.

Sludge lancing had been performed on all four generators on Unit 1 during the second (1985), third (1986), and fifth (1988) refueling outages. A total of 170 pounds, 254 pounds, and 630 pounds respectively was removed from the four generators. The licensee indicated that the large increase in the amount of sludge removed between 1986 and 1988 was probably due to the lancing being performed every other outage which allowed more sludge buildup. For Unit 2, sludge lancing had been performed during the first (1985), third (1987), and fifth (1989) refueling outages. For the first and third refueling outages, a total of 110 pounds and 420 pounds was removed. Unit 2 was currently in its fifth refueling outage and the sludge lancing had not been completed. The licensee had completed lancing on one generator and partial lancing of a second and removed a total of 150 pounds. From these results, the licensee estimated 400 to 500 pounds would be removed from the four generators.

The licensee performed eddy current testing of the Units 1 and 2 steam generator during the refueling outages. In general, the tests consisted of 3 percent random sampling; periphery rows for damage from loose parts; preheater rows for defects from preheater expansion; rows 1 and 2 for U-bend stress, and previously identified defects. Additionally, for the past three years, the licensee had performed eddy current testing of 100 percent of the hot leg tube sheet for both units. The licensee was planning to increase the random sampling from 3 percent to 20 percent in order to be consistent with the EPRI recent guidelines. During the current outage, the licensee was performing testing of 100 percent of all Unit 2 hot leg tube plugs and selected cold leg plugs for plug cracking. During the next Unit 1 refueling outage, the licensee was planning to test hot leg plugs but had not decided upon the percentage to be tested. Units 1 and 2 eddy current testing resulted in a total of 847 plugged tubes for Unit 1 and 755 plugged tubes for Unit 2 (not including the current outage). The number of plugged tubes for Unit 1 and 2 represented 4.5 percent and 4.0 percent of the total number of tubes in the generators. The major cause for plugged tubes was PSSCC with 726 tubes in Unit 1 and 754 tubes in Unit 2 being plugged for this reason. At the time of this inspection, the licensee had completed eddy current testing of Unit 2 steam generators A and D and had plugged an additional 107 tubes in the two generators.

The licensee had not experienced a primary to secondary tube leak for Unit 2 during the past five years. For Unit 1, a tube rupture occurred during March 1989, and was the subject of an augmented inspection (50-369/89-06). Subsequent to the special inspection, the licensee determined that the probable cause of the rupture was a tube installed with a slight defect-a shallow groove. Surface contamination collected in the groove and caused a crack to develop. Current leak rates for both units were estimated to be two to four gallons per day.

A hotsoak of all steam generators was performed during the cooldown prior to a refueling outage. The purpose of the hotsoak was to reduce hideout return. Hideout return can be defined as chemical contaminants that collect or "hideout" in steam generator crevices during power operation and then return to the liquid as temperature is reduced. The inspector reviewed hotsoak data for Unit 1 end-of-cycle (EOC) 5 (1988) and Unit 2 EOC 5 (1989) and the licensee's evaluation of the data for Unit 1 EOC 5. Unit 1 EOC 5 hideout return data showed an increase in sulfates over Unit 1 EOC 4 data which would have the effect of making potential crevice solutions less alkaline. The licensee identified a possible cause for the increase in sulfates to be the intrusion of filtered water via the makeup system. The licensee had also observed an increase in sulfates for the Unit 2 EOC 4 hotsoak and again attributed the increase to the filtered water ingress. At the time of the inspection, the licensee was evaluating the data from the recent hotsoak (EOC 5) on Unit 2. Since the sulfate concentration dropped to less than 100 ppb in approximately 12 hours rather than 24 hours the licensee was expecting a decrease in sulfates as compared to the Unit 2 EOC 4 hideout results.

(4) Secondary System Corrosion Product Transport Study

The licensee conducted a corrosion product transport study for the Unit 1 secondary system from January 20 through February 9, 1989. The study was conducted to determine the sources of various corrosion products within the system and subsequent transport to the steam generators. Six sampling points were established which consisted of the hotwell pump discharge, condensate polisher influent, condensate polisher effluent, "C" high pressure heater drain tank, final feedwater, and steam generator blowdown "D". After two sets of samples, sampling of the condensate polisher effluent was ceased and sampling of the "G" heater drain tank was initiated. The sampling train consisted of one 0.45 micron millipore membrane to collect filterable species and three cation resin impregnated filters to remove ionic species. The samples were then sent to the Duke Power Applied Science Center for analysis. The results of the analyses showed that 99.5 percent of the iron species in feedwater was filterable and that the condensate polishers removed 99 percent of the iron. The highest contribution of iron to the feedwater was the high pressure heater drain tank with 56 percent. The "G" heater supplied 16 percent of the iron to the feedwater. Based upon visual inspection of the samples, hematite (Fe_2O_3) was predominant in the condensate while magnatite (Fe_3O_4) was predominant in the feedwater. The study concluded that since the largest contributor of iron to the feedwater was the high pressure drain tank, the reduction of erosion/corrosion rates in systems that drained to the tank would reduce feedwater iron concentrations. These systems would be the moisture separators, moisture separator reheaters, and the A, B, and C high pressure heater drains.

(5) Summary

The licensee had maintained primary chemistry well within TS requirements and secondary chemistry well within the limits recommended by the EPRI/SGOG. Good control was evidenced by:

- Low Levels of ionic contaminants in the primary and secondary systems.

- Continuous surveillance of air inleakage into the main condenser and low dissolved oxygen levels in the condenser hotwell.

- Moderate amounts of sludge removed by sludge lancing steam generators, approximately 100 to 125 pounds per steam generator.

- Increased eddy current testing of the steam generators in response to the March 1989 Unit 2 tube rupture.

The licensee had established a nuclear chemistry goals program during early 1988 to monitor chemistry parameters of major plant systems and to improve chemistry control. The numerical goals were established based upon past chemistry data and recent trends. Unit 1 1988 secondary chemistry parameters of cation conductivity, sodium, chloride, sulfate, and hotwell dissolved oxygen showed an improvement over a previous two years' average. Of note was a reduction in cation conductivity from 0.172 umho/cm to 0.157 umho/cm and hotwell dissolved oxygen from 2.4 ppb to 1.1 ppb. Unit 2 also achieved a decrease in cation conductivity from 0.19 umho/cm (two year average) to 0.166 umho/cm (1988 result) and in hotwell dissolved oxygen from 2.2 ppb (two year average) to 1.7 ppb (1988 value). However, because of the October 1988 condenser leak, 1988 sodium, chloride, and sulfate values were greater than the previous two year average values.

c. Review of the Licensee's Chemistry Control Program

(1) Organization

The Chemistry Department was staffed by a total of 67 people including 14 supervisors. The department had undergone a major reorganization of shift and day personnel during May 1989. The reorganization more evenly distributed the work load and provided supervision on the backshift. On September 1, 1989, the current station chemistry manager would be reassigned for two years operator licensing school, and the manager's position would be filled by the previous chemistry manager who had completed the licensing school.

(2) Data Management and Review

The inspector reviewed graphed data acquired by the primary and secondary laboratories during the past two years. The licensee maintained a computerized bank of primary and secondary analytical results. Chemistry technicians entered analytical data into the computer network which would be checked by a second technician and then reviewed by management. The computer program could also supply graphed results for a designated time period for trending purposes.

(3) Laboratory Facilities

The inspector toured the primary and secondary chemistry laboratories and discussed instrumentation with licensee representatives. The secondary laboratory was equipped with inline monitors for sodium, dissolved oxygen, hydrazine, cation conductivity, and specific conductivity. The laboratory also contained an inline ion chromatograph for sodium, ammonia, chloride, and sulfate determinations. The original inline ion chromatograph had been installed in 1983. The licensee was currently finishing testing of a new chromatograph which would replace the original instrument this year. Dissolved oxygen and hydrazine monitors had been upgraded within the past two years. Beginning October 1989, the licensee was planning to upgrade all monitors which currently used chart recorders to digital read-outs with data storage by computer. This would allow online data acquisition and trending. The laboratory was also equipped with sampling sinks for collecting secondary chemistry samples.

d. Biological Fouling and Problems with the Service Water System

Both units of McGuire obtained make-up water for service water systems from Lake Norman. The plant had experienced few problems thus far with microbiological included corrosion and asiatic clam infestation in the service water systems. Clams were found in the fire protection system several years ago and a closed loop chlorination system had been installed for clam control. Currently there were no other significant clam prevention or monitoring programs in place. The plant had experienced some problems with deposit buildup in heat exchangers which used raw water for cooling. The containment spray (NS) heat exchangers used lake water on the shell side for cooling which made cleaning the systems more difficult. Currently, quarterly heat transfer tests were being performed and in December 1988 the licensee had used a new cleaning solution composed of surfactants, bioc des and dispersants. The new method proved effective in cleaning the raw water side of the heat exchangers. Fouling in the component cooling (KC) heat exchangers was monitored by differential pressure testing and daily trending of the data. The current number of plugged tubes in each KC heat exchanger was 14, 13, 6, and 13 in heat exchanger 1A, 1B, 2A, and 2B respectively. Twenty was the maximum number allowed. The licensee indicated that heat exchanger 2A had 20 percent to 50 percent through wall pitting in approximately 1,100 tubes out of a total of 4,100 and the possibility existed for retubing at a later date.

No violations or deviations were identified.

4. Environmental Monitoring (84750)

The inspector reviewed the licensee's Environmental Report for 1988. The report identified increasing trends for tritium in drinking and surface water, Cs-137 in shoreline sediment and Cs-134 in fish. Although average tritium concentrations in drinking water decreased from 1,350 pCi/liter in 1987 to 992 pCi/liter in 1988, the 1988 value was greater than the nine year average of 520 pCi/liter. Average tritium concentrations in surface water increased slightly from 920 pCi/liter in 1987 to 940 pCi/liter in 1988. Average Cs-137 concentrations in shoreline sediment increased from 165 pCi/kg-dry in 1987 to 266 pCi/kg-dry in 1988. Cesium 134 levels in fish remained essentially constant from 26.0 pCi/kg wet in 1987 to 27.0 pCi/kg wet in 1988.

No violations or deviations were identified.

5. Steam Generator Blowdown Recycle (BB) System (84750)

Steam generator blowdown was routinely directed through the condensate polishers for cleaning and for maintaining secondary chemistry parameters. The blowdown rate for each generator was approximately 99 gallons per minute (gpm) of which 30 percent flashed to steam, and the condensate polishers had the capacity to accommodate the blowdown from all four generators per unit. The blowdown recycle system had the capacity to isolate and route the blowdown of one steam generator through a separate train of a heat exchanger, recycle demineralizer, and filters. This recycle system was designed to be used during emergencies (i.e., steam generator tube rupture) or abnormal plant conditions and could accommodate blowdown of only 50 gpm. The heat exchanger for this train used nuclear service water (RN) on the shell side for cooling and the system did not have a radiation monitor on the service water discharge from the exchanger. During an emergency with a primary to secondary leak, a possible unmonitored release pathway existed if the recycle system was used and the BB heat exchanger leaked.

The inspector and licensee discussed the history and current status of the BB systems, and also the corrective actions that have been taken to prevent any unmonitored releases. Per discussions with cognizant licensee representatives, the inspector determined that the Unit 2 BB system had been put in service for functional testing only and had not been used to recycle blowdown. The Unit 1 BB system was functionally tested and used once for nine days during February 1988. At that time, the normal flow path for steam generator blowdown was isolated due to repairs on the blowdown blowoff tank. The BB system was used to maintain secondary chemistry, and the blowdown flow from all four Unit 1 steam generators was throttled down in order to accommodate the 50 gpm limit of the BB system.

The plant did not have a steam generator primary to secondary leak at that time. During the February 1988 use, a leak was suspected in the Unit 1 BB heat exchanger and subsequent pressure tests confirmed this. The inspector reviewed the licensee's problem investigation report 0-M88-0062, dated March 18, 1988, which discussed the leaks and specified that the heat exchangers were to remain out of service until design engineering could evaluate the problem. The Unit 1 heat exchanger was eddy current tested during May 1988 and the testing revealed localized tube wall thinning and leakage. A special tube plugging system had to be purchased due to the unusual support foundations of the heat exchanger and additionally, a hydro system had to be developed which allowed a test of the individual plugs. In January 1989, two leaking tubes were plugged and a vendor was developing a method to stabilize the tubes. The licensee determined that the original tube damage in the heat exchanger had been possibly caused by vibration. During the exchanger repair, it was discovered that the temporary clamps on piping expansion joints had never been removed. These clamps were installed to prevent movement and damage of the joints during transportation and installation. However, the clamps also prevented the shell expansion with the heated tubes and compressed the tubes causing possible vibrational damage. The clamps were removed and a subsequent inspection of the Unit 2 BB heat exchanger revealed no similar clamps. During February 1989 the Unit 1 heat exchanger was returned to service and a work request was written to install stabilization bars and to plug all tubes with greater than 50 percent wall thinning.

During the Unit 1 steam generator tube rupture in March 1989, additional heat exchanger tubes were plugged so that the system could be used to isolate blowdown from the ruptured generator. However, due to past operational problems, the licensee chose not to use the BB system but relied on the normal blowdown flowpath. At the time of this inspection, the stabilizer bars had not been installed.

The inspector and licensee discussed additional corrective actions for the possible unmonitored release pathway. The Unit's 1 and 2 BB systems had been tagged out-of-service and would remain so until the situation was resolved. In order to monitor RN discharge from the BB heat exchanger, the licensee was considering moving the EMF-32 effluent monitor, that currently monitored the BB recycle demineralizer outlet, to the RN discharge site of the exchanger. The inspector reviewed the station problem report SPR-2520 dated May 8, 1989, concerning this possible relocation of the EMF-32. The report had been sent to Operations on May 29, 1989, for evaluation and Operations' analysis had not been completed as yet. Radiation Protection personnel had initiated a requirement for two hour sampling intervals on the RN discharge side if the BB system were to be used. This requirement was documented in the procedure HP/0/B/1009/18, "Radiation Protection Response to Indication of a Primary to Secondary Leak," dated April 28, 1989. The licensee was additionally installing a new modification to the routine blowdown system which included a heat exchanger, prefilter, and demineralizer with a 400 gpm flow capacity. The new heat exchanger would use condensate (CM) water for cooling. This modification was installed and inservice for Unit 1 by June 1989. Unit 2's system was currently being installed and expected to be operational during 1989.

No violations or deviations were identified.

6. Exit Interview

The inspection scope and results were summarized on August 11, 1989, 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.

The licensee had maintained an acceptable water chemistry program on the primary and secondary system. Good contact was evidenced by:

- Low levels of ionic contaminants in primary and secondary systems (Paragraphs 3.a and 3.b).
- Continuous surveillance of air inleakage into the main condenser and low dissolved oxygen levels in the condenser hotwell (Paragraph 3.b.1).
- Moderate amounts of sludge removed by sludge lancing the steam generators (Paragraph 3.b.3).
- Increased eddy current testing of the steam generator in response to the EPRI guidelines and the March 1989 tube rupture (Paragraph 3.b.3).

The status of the steam generator blowdown recycle system and corrective actions for the possible unmonitored release pathway were discussed (Paragraph 5).

Two violations (Paragraphs 2.a and 2.c) were closed. The violations concerned failure of the Semiannual Effluent Release report to include descriptions of abnormal releases and failure to conduct adequate Fe-55 analyses for liquid effluent release measurements.

One URI (Paragraph 2.b) remained open concerning the radioiodine and particulate sampling requirements of NUREG-0737 IIF.1-2. Licensee management verbally committed to install the heat tracing to outside sampling lines by October 31, 1989.