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

SEP 0 7 1988

Report Nos.: 50-338/88-25 and 50-339/88-25

Licensee: Virginia Electric and Power Company
Richmond, VA 23261

Docket Nos.: 50-338 and 50-339 License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: August 8-12, 1988

Inspector: John B. Kahle 9/2/88
P. G. Stoddart Date Signed

Accompanying Personnel: W. J. Ross

Approved by: John B. Kahle 9/2/88
J. B. Kahle, Section Chief Date Signed
Division of Radiation Safety and Safeguards

SUMMARY

Scope: This routine, unannounced inspection was conducted in the areas of plant chemistry, chemical corrosion, and pipe wall thinning.

Results: The licensee continued to experience difficulties in the control of chemistry (during startup) and corrosion, especially in Unit 1. Considerable attention and resources were being given to the integrity of the steam generators; however, these efforts were made difficult by degradation (general corrosion and denting) that had been initiated during the early years of plant operations. A very effective on-line chemistry monitoring system had been completed and made operational. All of the chemistry supervisors, as well as the Technical Support Superintendent had been replaced during the last year. No violations, deviations or program weaknesses were identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

L. Boggs, Chemistry Planner, Chemistry
*M. Bowling, Assistant Station Manager
T. Brauer, Primary Coordinator, Chemistry
R. Clark, Plant Engineer, Engineering
D. Fortin, Corporate Inservice Inspection Engineer
E. Frese, Corporate Chemist
D. Greene, Corporate Inservice Inspection Engineer
S. Hammil, Plant Inservice Inspection Supervisor
L. Hartz, Plant Instrument and Control Supervisor
D. Heacock, Technical Support Superintendent
L. Jones, Systems Engineer/Chemistry
L. Lee, Senior Chemist, Chemistry
R. Lee, Nuclear Engineer, Site Engineering
P. Morck, Secondary Coordinator, Chemistry
*P. Sloane, Assistant Supervisor, Chemistry
J. Wroniewicz, Site Engineering Supervisor

NRC Resident Inspectors

*J. Caldwell
L. King

2. Plant Chemistry (79701)

This inspection was a continuation of a program designed to assess the licensee's capability to prevent degradation of the primary coolant pressure boundary and other plant systems from chemical corrosion or erosion. During previous inspections, the major areas of concern had been related to plant systems, e.g., ingress of contaminants through the main condenser and water treatment plant, reduced effectivenesses of the condensate polishers, and the deteriorating condition of the steam generators, especially those in Unit 1. During this inspection the inspector reviewed and re-evaluated the condition and performance of components and systems within the secondary coolant system, as well as the effectiveness of the licensee's chemistry control program for preventing loss of integrity of steam generator tubes and for minimizing pipe wall thinning.

a. Plant Status

Since the last inspection in this area (see Inspection Report Nos. 50-338/87-17 and 50-339/87-17 dated June 24, 1987), Unit 1 had undergone a three month shutdown (July-October 1987) as a result of a steam generator tube rupture caused by mechanical stress. Stable operation at full power had been further delayed until December 10, 1987. After one month at full power operation, this unit was again shutdown for thirty days because of leakage of resin from the condensate polishers into the steam generators. Subsequently, this unit operated in a stable condition until it tripped on August 6, 1988, because of an electrical problem. During the period of the inspection, the unit was being held in a "chemistry hold" at five percent power until the quality of the steam generator water (particularly the concentration of sulfate) could be reduced below the Action II level limit. (This limit was defined by the Steam Generator Owner's Group (SGOG) and the Electric Power Research Institute (EPRI) in guidelines for protecting steam generators from corrosion.) Unit 1 returned to Action Level I on August 12 and to full power on August 13, 1988.

In July 1987, Unit 2 began a reduction leading to a refueling outage that began on October 1987 and ended November 16, 1987. Since that time, Unit 2 had operated in a very stable condition. In March 1988, after a three-day outage related to valve checks, a seven-hour "chemistry hold" had been required to achieve the required level of chemical purity of the steam generator water at greater than 30 percent power.

The lengthy times required for chemistry holds were discussed in depth with the licensee as being indicative of chemistry problems. In essentially all cases, the licensee had already recognized the problem areas and had established programs to address them.

b. Review of Effectiveness of Components

Through an audit of chemistry control data and discussions with cognizant licensee personnel, the inspector reviewed the effectivenesses of key parts of the secondary coolant system and balance of plant during the past year. This review also included licensee's activities to prevent or to correct problems related to these components.

(1) Main Condensers

The effectiveness of the main condensers as barriers to ingress of potential corrodants had been enhanced significantly since 1986 when the licensee began to coordinate condenser cooling water flow with temperature so as to minimize vibration of the condenser tubes and leakage at tube-tube sheet joints. However, Unit 1 experienced a measurable condenser leak in March 1988. The presence of sodium and chloride hideout in the steam generators of Unit [illegible] indicated that the condensers might still be the source of [illegible]aking lake water, possibly through tube seam welds. How[illegible], the purity of the hotwell water in both units remained b[illegible]r than administrative limits; i.e., the cation conductivity remained less than 0.2 umho/cm. Similarly, inleakage of air had been kept low (less than 6 SCFM); consequently the dissolved oxygen content of the hotwell water had also been low (typically 3-5 ppb).

The improved reliability of the condenser tubes was attributed to continued use of an Amertap tube - cleaning system, biannual hydrolasing of all condenser tubes, and eddy current testing of a minimum of three percent of condenser tubes at each refueling outage. Tests for air inleakage were being performed weekly. Finally, the new online monitoring system sampled hotwell water and provided a continuous record of water purity to help in identifying condenser leaks.

(2) Service Water System

The inspector was informed that as followup to the mechanical (hydrolasing) program performed in 1986 to clean the Service Water System, plans were being made to chemically clean the system in September - October 1988. An iron-chelating reagent was to be used in an effort to remove corrosion products from both carbon steel and stainless steel pipes so that continued treatment of the inner surfaces with a biocide would be more effective in preventing microbiologically induced corrosion (MIC). The program had been designed so that possible attack of such materials as base pipe metal and weld metals could be monitored.

(3) Water Treatment Plant

The licensee was continuing to use a contractor to provide high purity water for makeup purposes by means of a portable reverse osmosis unit.

(4) Condensate Cleanup System

The effectiveness of the condensate cleanup system was being affected adversely by the same factors observed during previous inspections. Other than during unit startup, polishing was being performed by only two of the six available filter-demineralizer units, which were used primarily as a means of controlling pH of the secondary cooling system (by removing ammonia from the condensate). Consequently, only about 400 gpm, or ten percent, of the total condensate was being polished when the unit was at full power. During this inspection, two filter-demineralizer beds in each unit were inoperable because they were undergoing maintenance.

Even without full-flow polishing, the concentrations of impurities in the feedwater had been kept much lower than the upper limits recommended by the (SGOG) and Westinghouse (i.e., cation conductivity had typically been less than 0.2 umho/cm).

However, ion exchange resins continued to leak through the filter-demineralizer tubes and into the steam generators, where the resins were thermally degraded to form sulfate ions. Plans were underway to equip these tubes with rigid, 70-mesh metal inserts in an effort to provide a better barrier against transfer of resins into the feedwater.

(5) Feedwater Heaters

During the inspection of June 1987, the inspector had noted that the copper alloy tubes in feedwater heaters Nos. 5 and 6 had been replaced with type 304 stainless steel tubes. The same replacements were made in Unit 2 during the last refueling outage. The inspector was informed that the copper-alloy tubes in two of the remaining four heaters would be replaced during each of the next two refueling outages for each unit. All of these heaters had been included in the licensee's heat exchanger surveillance program, and twenty-five percent of the tubes had been eddy current tested each refueling outage.

(6) Steam Generators

As mentioned earlier, the effectiveness of the steam generators, especially those in Unit 1, had continued to deteriorate as indicated by the following:

- As the result of eddy current tests, during the 1987 refueling outages, 343 additional tubes had to be plugged in the three Unit 1 steam generators and 155 additional tubes in Unit 2. Consequently, as of the time of this inspection, the following percentages of tubes had been plugged -

1A	9.3%
1B	6.4%
1C	11.2%
IIA	4.4%
IIB	3.8%
IIC	4.9%

- The following amounts of solid corrosion products (iron and copper oxides) were removed from the six steam generators during the 1987 outages:

1A	667	pounds
1B	1610	pounds
1C	1255	pounds
IIA	270	pounds
IIB	203	pounds
IIC	265	pounds

- Several hundred parts per billion of potentially corrosive "hideout" ions, such as sodium, chloride, and sulfate still were observed during plant startup and cooldown and had been the cause of lengthy "chemistry holds" during startups. Elimination of these ions, and of even larger amounts of silica, by means of hideout return blowdown was not as efficient as desired because of the limited rate of blowdown (30 - 35 gpm) of each of the steam generators. In an effort to maximize cleanup, blowdown water was always being discarded as waste rather than being recycled as condensate.

  Since "hideout" species tend to become less soluble and precipitate into crevices or in sludge piles when the power level increases, the apparent purity of the steam generator water improves. During the past year the purity of steam generator water in both units had been better than the limits recommended by the SGOG for corrosion control. The concentrations of sodium, chloride, and sulfate had typically each been less than 5 ppb. However, the cation conductivity of this water had remained between 0.2 and 0.4 umho/cm, even after being corrected for the presence of 5 to 6 ppm of boric acid in the steam generator water. The magnitude of the cation conductivity indicated that additional soluble anionic species (other than chloride and sulfate) were contaminating the steam generator water.

(7) Chemistry Control

Because of increased concern regarding pipe wall thinning, as well as over the licensee's difficulties with the integrity of steam generator tubes, the control of chemistry of the secondary system was reviewed in depth. The licensee was continuing to implement an AVT (all volatile treatment) chemistry control program that had been modified to use hydrazine to control pH (through degradation of the hydrazine to ammonia) as well as to remove dissolved oxygen. Also, a concentration of 5 to 6 ppm of boric acid was being maintained in the steam generator water to prevent tube denting. The resulting pH was near the lower limit of the range (8.8 - 9.2) recommended for PWRs with copper-containing components such as feedwater heater tubes. However, the presence of boric acid caused the pH of steam generator water, as measured at 25°C, to be depressed to approximately 7.5. Even though a low pH is considered to be conducive to acidic (general) corrosion of non-alloyed ferrous materials, this pH was within the operating guidelines (7.00 - 9.20) set by Westinghouse. (Note: At the operating temperature of the steam generator [>500°F], the actual pH would be greater because ionization of boric acid is reduced at higher temperatures).

Control of the pH of water/steam throughout the high pressure steam and drain lines depends on the concentrations of ammonia (which tends to fractionate into the steam phase) and of boric acid (approximately ten percent volatilizes with steam and tends to fractionate into the condensate phase). The inspector was informed that further modification of AVT chemistry control was under study whereby morpholine also would be added to the feedwater. Morpholine has been shown to preferentially condense in two-phase systems and would increase the pH of these wet steam systems, and thereby diminish the possibility of general corrosion of carbon steel pipe.

The inspector was informed that the following programs had been initiated or upgraded with the goals of minimizing pipe wall thinning as well as protecting steam generators from corrosion:

- Reviewing the effect of morpholine on plant materials and systems, including condensate demineralizers.
- Implementing an additional inservice inspection program during refueling outages to monitor pipe wall thinning in single-phase and two-phase systems.
- Implementing a corporate study of corrosion product transport at the licensee's Surry Nuclear Power Station.

(8) Conclusions

During the past year, the licensee had continued to prevent or minimize ingress of contaminants into the secondary coolant systems of both units. However, relatively large amounts of hideout return were still being observed. The licensee attributed this apparent anomaly to five factors:

- incomplete removal of crevice hideout by blowdown of steam generators.
- undetected condenser leaks over extended periods of time when the units were operating in a stable manner.
- operation of the condensate polishers at only ten percent flow when the units were operating at full power.
- leakage of ion exchange resins from the condensate polishers.
- limited blowdown capacity.

Large amounts of corrosion products, originating from carbon steel pipe and copper alloy feedwater heater tubes, continued to be transported to the steam generators. This situation is now viewed with increased concern as evidence of pipe wall thinning as well as contributing to the formation of conditions within the steam generators known to be conducive to corrosion/cracking of steam generator tubes. The licensee was attempting to modify AVT chemistry control to prevent general corrosion as well as to prevent denting. These actions continued to be complicated by inefficient operation of condensate polishers and the presence of copper alloy feedwater heater tubes.

The inspector was informed that plans have been initiated to replace the steam generators in Unit 1. The time required to complete these plans will provide the licensee an opportunity to improve the effectiveness of the remainder of the secondary systems in both units.

c. Review of the Licensee's Chemistry Program

Through discussions with cognizant licensee personnel and a walk-down of sampling panels and laboratories, the inspector reviewed and re-assessed the licensee's capability to control primary and secondary chemistry. Two major changes had been made in the past year; i.e., new appointments had been made to the positions of Superintendent of Technical Services, Chemistry Supervisor, and Assistant Chemistry Supervisor, and the Westinghouse online chemistry monitoring system had been made operable. Inasmuch as the new superintendent and supervisors had previous experience in plant or corporate programs related to chemistry, these personnel changes were not considered to be detrimental to the licensee's capability to control chemistry.

The computer-controlled online chemistry monitoring system provided the licensee with the capability to continuously monitor all chemistry control parameters, with the exception of sulfate, (i.e., chloride, sodium, hydrazine, cation conductivity, and specific conductivity) at key locations throughout the secondary coolant system. Consequently, through the use of a computer terminal in the chemistry laboratory, the chemistry staff could follow short and long term trends, identify inleakage of contaminants, calibrate the online instruments, and provide real time chemistry information to plant management in graphic or numerical form. The inspector observed that these capabilities were being effectively used to monitor the levels of hideout return and purity of steam generator water during the startup of Unit 1.

State-of-the-art laboratory analytical instrumentation, such as an ion chromatograph and atomic absorption spectrophotometer were being used to supplement the online monitoring system. All chemistry technicians were being trained in the operation and maintenance of these instruments.

The licensee had also assigned an experienced plant chemist as a System Engineer who was dedicated to the improvement of chemistry and corrosion control.

In addition to the efforts being placed on the control of secondary coolant chemistry, the chemistry staff had initiated two new changes for primary water chemistry control. In an effort to reduce the levels of out-of-core radiation during maintenance on steam generators and other components in contact with the reactor coolant, the licensee was maintaining the lithium/boron ratio at the highest value recommended by Westinghouse. By maintaining high pH levels, the licensee was attempting to minimize transport of activation products (cobalt-58 and cobalt-60) throughout the reactor coolant system. Secondly, the overpressure of hydrogen had been reduced so as to lower the upper solubility limit for hydrogen in the reactor coolant from 50 cc/kg to 35 cc/kg. This action was taken in response to recently acquired information that high concentrations of dissolved hydrogen are conducive to primary-side stress corrosion cracking of steam generator tubes.

As part of a NRC program to validate analytical capabilities at nuclear power plants, the inspector requested that the Chemistry staff analyze a series of samples prepared by Brookhaven National Laboratory. These samples were solutions of chemistry species typically monitored at PWRs for control and diagnostic purposes. The goals of this program were to evaluate the accuracy and precision of the licensee's measurements and, where appropriate, to identify causes of errors (e.g., comprehension and techniques of analysts, adequacy of procedures, and calibration of instruments).

The samples were to be analyzed in triplicate by three different technicians. However, because of the increased work load of the chemistry staff caused by the startup of Unit 1, these samples were not analysed during the inspection period. The inspector requested that the samples be analysed as soon as convenient, and that the results be transmitted to the inspector for review and inclusion in a later report. This action will be tracked as IFI 50-338, 339/88-25-01,
Analysis of NRC Non-Radiological Crosscheck Samples.

Conclusions - During this inspection, no violations or deviations were identified. The purity of the reactor water was being maintained at higher levels than required by Technical Specifications. The licensee's overall chemistry program was considered to meet the intent of Technical Specifications, Generic Letter 85-02, and the SGOG/EPRI guidelines.

3. Exit Interview

The inspection scope and results were summarized on August 12, 1988, with those persons indicated in Paragraph 1. The inspector described the areas inspected and discussed the inspection results. Although proprietary information was reviewed during this inspection, none is contained in this report.