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

Report Nos.: 50-280/90-38 and 50-281/90-38

Licensee: Virginia Electric and Power Company
Glen Allen, VA 23060

Docket Nos.: 50-280 and 50-281 License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: December 10-14, 1990

Inspectors: R Moore 1/4/91
R. Moore Date Signed

McKenzie Thomas 1-3-91
M. Thomas Date Signed

Approved by: Frank Jape 1/4/91
F. Jape, Chief Date Signed
Engineering Assessment Section
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope:

This routine, unannounced inspection was conducted in the areas of design change and modifications, engineering technical support, and follow-up on previous inspection findings.

Results:

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

The DCPs reviewed by the inspectors appeared to be adequately implemented. Licensee efforts to enhance the overall DCP process are positive indications of management's involvement in the DCP process. Efforts to reduce the EWR backlog have proven to be effective.

Restructuring of engineering resources and programs, began in 1989, was generally complete. Adequate product was available demonstrating the improved effectiveness of engineering technical support at Surry. The system engineering and root cause analysis programs were well structured and implemented. The high level of technical staff involvement in the deficiency reporting program was a strength.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *R. Bilyeau, Licensing Engineer
   R. Boles, SE
   *M. Bowling, Manager, Licensing and Programs
   W. Corbin, Supervisor, Project Engineering (Surry), Nuclear Engineering Services
   A. Fletcher, Assistant Superintendent, Site Engineering
   A. Hall, SE
   *D. Hart, QA Supervisor
   *M. Kansler, Plant Manager
   T. Kendzia, Supervisor, SNS
   J. Laflam, SE
   *T. Sowers, Superintendent, Site Engineering
   S. Semmes, SE

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

   NRC Resident Inspectors

   *W. Holland

   *Attended exit interview

2. Design, Design Changes and Modifications (37700)

   <u>Modifications</u>

   The inspectors reviewed the modification packages listed below to verify the adequacy of the 10 CFR 50.59 evaluations, verify that the design changes were prepared and being installed in accordance with licensee administrative procedures and applicable industry codes and standards, field changes were reviewed and approved in accordance with administrative controls, and post modification test requirements were specified. The following modifications were reviewed.

   a. DCP 87-28, Component Cooling Heat Exchanger Replacement

      This DCP replaced CC heat exchangers 1-CC-E-1A and 1-CC-E-1B. The heat exchangers were replaced because of the high corrosion and erosion rate of the HX copper nickel tubes. The corrosion was caused by high levels of sulfate reducing bacteria which resulted in a pitting attack on the copper nickel base alloys. To provide for better protection against erosion and corrosion, the new HXs have titanium tubes and titanium clad carbon steel tube sheets. The old HXs were built in accordance with the requirements of ASME Section III, 1968 edition. The new HXs were built in accordance with the requirements of ASME Section VIII, 1986 edition. By letter to the NRC dated July 23, 1987, the licensee requested relief from certain ASME Code requirements. The NRC granted the licensee's relief request in a letter dated February 25, 1988.

b. DCP 90-26, HX Service Water Piping Cleaning and Recoating, Surry Unit 1

This modification involved cleaning the affected SW piping of its existing coating; inspecting and repairing any piping corrosion pitting; and recoating the piping with a material that will improve system operating characteristics. The old coating was a coal tar epoxy. The new coating was a 100 percent solids epoxy. The pipe cleaning involved a four-step process:

(1) Hydrolazing to remove gross buildup;

(2) Detailed inspection of the cleaned piping to determine the location of local corrosion pitting;

(3) Repair of the piping via a weld repair at the perforation or pit where excessive corrosion of the pipe wall was found;

(4) Abrasively blast cleaning the system to remove all remaining corrosion products and coal tar epoxy.

The pipe coating process involved repairing corrosion pits that were determined not to require weld repairs by using the epoxy repair putty; and applying the coating.

The other purpose of this DCP was to install pressure taps upstream of valves SW-MOV-104B,-104C,-105B,-105C. These pressure taps are used to perform flow testing of the B and C RSHXs. The piping inspection, cleaning, and installation of the pressure taps for flow testing were done in response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment. The GL recommended establishment of an SW piping surveillance program.

c. EWR 90-330, Recirculation Spray Heat Exchanger Piping Inspection and Cleaning, Surry Unit 2

This modification involved inspecting and cleaning the Unit 2 RSHX supply piping. This inspection was determined to be necessary based on the results found during implementation of DCP 90-26. The purpose of the hydrolazing and mechanical cleaning was to rid the piping system of biofouling, remove any loose coal tar epoxy coating that was still attached to the piping, and remove any loose corrosion deposits from the piping walls.

Unit 2 was operating at power when it was determined that the RSHX supply piping needed to be inspected. Unit 2 was shut down in order for this EWR to be implemented. This issue is discussed in greater details in NRC Inspection Report 50-280, 281/90-36, and LER 90-14 dated November 21, 1990.

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

Engineering Work Requests

The inspectors reviewed EWR performance data and the licensee's efforts to reduce the backlog of unanswered EWRs. Licensee personnel stated that there was a backlog of approximately 600 unanswered EWRs approximately two years ago. The backlog of unanswered EWRs as of November 30, 1990, was 122. Licensee personnel stated that there were several factors which contributed to the reduction in the number of unanswered EWRs over the last two years. First, both units were shut down and additional engineering support was provided during 1989 to reduce the backlog. Other efforts included measures for prioritizing, screening, and using other systems available such as procurement reviews and the station management review team. All EWRs are reviewed by engineering. A number of the EWRs were procurement related issues which were handled through procurement document reviews by the station procurement engineering group. The management review team meets weekly to review EWRs which involve minor modifications and prioritizes the EWRs. Licensee personnel stated that their target is to reduce the number of backlog EWRs to an average of approximately 50.

The inspectors reviewed performance data which showed that the number of unanswered EWRs has steadily declined over the last 12 months from 297 to the current number of 122.

The inspectors consider the licensee's efforts to reduce the EWR backlog has been effective and is a positive example of management's involvement in providing quality and timely engineering support to the plant.

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

FCRs and Design Change Process

In addition to reviewing the DCPs the inspectors also held discussions with engineering personnel concerning the number of field changes in DCPs. Licensee personnel stated that they are evaluating causes for FCRs in an effort to develop corrective actions to reduce the number of FCRs in DCPs. One of the efforts includes implementing a pilot program during the upcoming Unit 2 refueling outage where the DCP implementing procedures will be developed by the Nuclear Site Services/Construction department, which has responsibility for implementing DCPs. Currently, the DCP implementing procedures are written by engineering.

Other efforts to improve the design change process include a DCP post implementation review. This review involves reviewing selected DCPs implemented during the current Unit 1 refueling outage, focusing on engineering, procurement, construction, and six months of operations if appropriate.

Additionally, Nuclear Engineering Services has set a target for completing engineering work on DCPs and providing the DCPs to the station for SNSOC review at least 90 days prior to a scheduled refueling outage. This will help station personnel in outage planning and scheduling. During review of the Unit 1 DCPs implemented during the current refueling outage, the inspectors noted that, although the target date was not met in all instances, the licensee's efforts to improve in this area are considered positive.

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

3. Engineering Technical Support

Overall, the Surry engineering and technical support capability has continued to mature since February 1990. Restructuring of engineering resources and programs, began in 1989, was generally complete. Adequate product was available demonstrating the improved effectiveness of engineering technical support at Surry. The SE program was well structured and SEs were effectively accomplishing their support responsibilities. A comprehensive root cause analysis program was developed and implemented early in 1990. The varying levels of root cause analysis accomplished in 1990 demonstrate the program was effectively implemented, and substantially improved performance was evident in this area since 1989. The engineering organization has developed and recently implemented self assessment activities to monitor overall engineering performance.

Onsite engineering services provided by the System Engineering and Station Nuclear Safety organizations were reviewed. The SE organization provided direct technical support to the plant via interfaces in maintenance, operations, testing, and design change activities. The SNS group provided administrative control for the plant deficiency reporting program (Deviation Reports) and performed the root cause analysis for those deficiencies and events requiring cause evaluations.

SE performance review encompassed interviews and review of documentation which demonstrated SE involvement in plant activities. The current SE program was outlined in SSES 3.01, Controlling Procedure for System Engineering, dated August 6, 1990. This procedure replaced the SE program procedure which was in use when the NRC reviewed the program in February 1990 (NRC Report No. 50-280, 281/90-20). The current procedure was incorporated to parallel the North Anna SE program. SSES 3.01 outlined an improved SE program with respect to guidance on system trending and tracking and how this information was to be documented and communicated to management. The specific structured requirements for system trending, tracking, and documentation were applied to Priority 1 systems. The trending, tracking, and documentation applied to Priority 2 and 3 systems was left to the discretion of the responsible SE. Engineering management categorized plant systems as Priority 1 based on the following criteria:

- Systems which have had significant problems that affect or could have affected reliable generation;
- Systems with poor maintenance histories which have been costly to maintain;
- Systems which have either essential safety or power generation functions;
- Systems which industry experience has determined to be unreliable or have had significant problems;
- Systems which cause significant chronic operational problems.

Surry implementation of SSES 3.01 was in the process of being scaled down to those aspects which management felt appropriate to the Surry station. Primarily, documentation of SE activities was to be reduced from that specified in the procedure. Engineering management stated the SE manhours would be more effective in field work and real time technical support than documentation functions. The indicated program adjustment did not represent a reduction in SE plant support but a reduction in direct objective evidence demonstrating SE real time and proactive activities.

There were 23 SEs with two supervisors. Approximately 90 systems were assigned; 16 of these were categorized as Priority 1. The documentation available demonstrated considerable proactive and real time involvement on Priority 1 systems. Discussions with four SEs demonstrated they were knowledgeable of system status on Priority 2 systems although trending functions were less developed. The biweekly STAT procedure provided a mechanism for routine review activities to evaluate system status. This checklist was applied to Priority 1 systems and included review of work orders, plant logs, ongoing projects, surveillance tests, DRS, CFEs, available trend information and performance of system walkdowns. The STAT procedures were begun in November 1990 and were performed for all 16 Priority 1 systems and three Priority 2 systems. The System Engineering Quarterly Report, Third Quarter 1990, provided a good overview of system activities and status for the Priority 1 systems. The STAT procedures and Quarterly Report provided a well structured methodology for monitoring and reporting system "health." In conclusion, program application to the Priority 1 systems was good. Program application to Priority 2 and 3 systems was less structured and defined; however, the SEs interviewed appeared knowledgeable of system status on these systems.

System Engineering involvement in plant activities was evident. In January 1990, SEs coordinated with the planning organization to identify work to be accomplished in the Unit 1 and 2 refueling outages. An inplant memorandum dated June 1, 1990, from the Maintenance Engineering Supervisor to the site Engineering Manager, highlighted the effective interaction of SE and maintenance engineering in accomplishing component failure evaluations. Other memoranda from SE demonstrated proactive SE activities, e.g., status of outstanding work request cards hanging in the EDG rooms, T.S. required heat trace circuits near failing criteria. Review of a sample of DRs for the previous four-month period demonstrated plant deficiencies identified by SEs. The Design Base Document review process involved SE. Several draft DBDs were being reviewed by SE. Nine DBDs were scheduled to be issued in March 1991.

The SNS group was responsible for administration of the DR program and implementation of the root cause analysis program at Surry. The staff of approximately 15 included STAs and technical personnel accomplishing external plant operating experience reviews and root cause analysis. Deviation Reports received root cause evaluations of varying depth in accordance with safety significance of the identified issues. A review of routine DRs demonstrated the lower level of cause analysis. The level of evaluation for the routine DRs reviewed was appropriate. DRs with identified or potential safety significance received a more involved Cause Determination Evaluation. The following CDEs were reviewed:

S1-90-637	S2-90-0079
S1-90-856	S1-90-0138
S1-90-740	S1-90-1405
S1-90-014	S1-90-1100

The cause evaluations accomplished for these CDEs were appropriate for the significance of the issue identified. Root Cause Evaluations were performed for those events or identified issues with significant impact on plant operations, i.e., reactor trips, major component failure. These evaluations were accomplished by a team of technical and discipline specialists and encompassed a comprehensive information gathering and analysis process. Approximately seven RCEs were initiated in 1990. The RCEs reviewed were generally adequate and appropriate to the significance of the identified issue. RCE 90-001 which evaluated the installation of an inappropriate Steam Generator level transmitter was comprehensive and the recommendations appropriately addressed the identified causes. RCE 90-008 addressed a failed Unit 2 MFRV. The conclusion that dirt and foreign material in the positioner air resulted in failure was reasonable; however, the corrective action to periodically replace the inlet filter orifice appeared minimal. The determined cause included unclean or wet instrument air but corrective action did not include evaluation or monitoring of instrument air quality in relation to the manufacturer's recommendation for these valves. The majority of the RCEs were awaiting a management review and approval. Corrective actions initiated from RCEs were entered into a commitment tracking system.

Overall the administrative control and trending of DRs was adequate. Approximately 2,400 DRs were initiated in 1990 with approximately 57 percent closed. Due to the upfront operability and reportability reviews performed, there was no apparent safety significance associated with the backlog of DRs. In addition to administrative control, approximately 35 percent of DRs were assigned to engineering for resolution. The high level of involvement in the DR process by the technical staff is a strength. Licensee QA Audit S90-14 of the DR program identified DRs which did not receive required CDEs. SNS responsiveness and corrective action for this finding was timely and effective. DRs were trended quarterly. The Station Deviation Trend Report, May-October 1990, provided an overview of DR-related trends and individual cause trends. A trend report was generated for the Unit 1 refueling outage which listed outage testing failures and associated corrective actions initiated.

Engineering self-assessment activity included periodic self-assessment of Engineering functions and programs, and a "customer" survey. Procedure SSES 1.09, Engineering Self-assessment Program, October 1, 1990, implemented the goals of the Engineer Quality Plan to initiate critical self-assessment activities. The program established specific performance indicators reflective of engineering functions, i.e., EWR backlog, DR response, QA findings, test deficiencies, etc. The November 1990 monthly engineering assessment demonstrated trends related to these indicators. Although the report contains tables and graphs representing these indicators there was no interpretation which translated the data into a meaningful assessment statement regarding engineering performance for the month. It was notable that the indicators were defined by a specific range of acceptance in conjunction with a Performance Annunicator Panel methodology being developed at Surry as part of a plant-wide self-assessment program. An opinion survey was distributed to the plant to evaluate site engineering performance in the areas of professionalism, performance, and communication. The survey was initiated in October 1990. On a scale of 1 (poor) to 10 (good), the survey demonstrated an overall opinion of approximately 7 in each area. The survey results reflected a general respect and reliability for SE and other site engineering services. The self-assessment program of SSES 1.09 and the survey demonstrated engineering actions to monitor and improve engineering technical support.

4. Action on Previous Inspection Findings (92701, 92702)

a. (Closed) Inspector Follow-up Item 280, 281/88-32-18: Wiring Discrepancies Between Drawings and As-built Conditions in the Main Control Board.

In response to this deficiency, the licensee performed walkdowns of the main control boards. Discrepancies identified resulted in the initiation of 83 Drawing Change Requests which were completed. Additional tagging and wiring discrepancies were identified on EWR 89-356. EWR 89-356 has not been completed; it has been entered into the scheduling process and continues to be tracked on the licensee's commitment tracking program. Licensee action on this issue was adequate for closure.

b. (Closed) Inspector Follow-up Item 280, 281/90-08-01, Setpoint Program Inconsistencies.

This item addressed inconsistencies between upper tier and lower tier program documents. Primarily, corporate Electrical Engineering Standard, EEN-0211, specified a structure and scope for the Setpoint Control Program that was not implemented by the Surry station program. Discussion with engineering personnel demonstrated aspects of EEN-0211 were not applicable to the Surry station. Corrective action was to delete EEN-0211 from the upper tier references for the setpoint program. This corrective action was completed.

5. Exit Interview

The inspection scope and results were summarized on December 14, 1990, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

6. Acronyms and Initialisms

ASME	American Society of Mechanical Engineers
CC	Component Cooling (System)
CDE	Cause Determination Evaluation
CFE	Component Failure Evaluation
DCP	Design Change Package
DR	Deviation Report (deficiency reporting program)
EDG	Emergency Diesel Generator
EWR	Engineering Work Request
FCR	Field Change Request
HX	Heat Exchanger
LER	Licensee Event Report
MFRV	Main Feedwater Regulating Valve
MOV	Motor Operated Valve
RSHX	Recirculation Spray Heat Exchanger
QA	Quality Assurance
SE	System Engineer (System Engineering)
SNSOC	Station Nuclear Safety and Operating Committee
STA	Shift Technical Advisor
STAT	System Trending and Tracking (Procedure)
SW	Service Water
TS	Technical Specification