U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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License Nos.:	NPF-2 and NPF-8
Report Nos.:	50-348/99-04 and 50-364/99-04
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Farley Nuclear Plant, Units 1 and 2
Location:	7388 N. State Highway 95 Columbia, AL 36319
Dates:	May 16 to June 26, 1999
Inspectors:	T. P. Johnson, Senior Resident Inspector R. K. Caldwell, Resident Inspector G. R. Wiseman, DRS Fire Protection Inspector (Sections F1.1 thru F8.1)
Approved by:	Pierce H. Skinner, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY
FARLEY NUCLEAR POWER PLANT UNITS 1 and 2
NRC Inspection Report 50-348/99-04 and 50-364/99-04

This integrated inspection to assure public health and safety included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection, and a specialist inspection of the fire protection program.

Operations

- Operator performance was excellent as noted during normal plant operations and in response to reactor trips on Unit 1 and on Unit 2. This strong performance included startup activities on both units, and response to a steam generator level transient on Unit 2 (Sections O1.1 to O1.4).

- Operator performance when switching lube oil coolers and during the load reduction, combined with procedural and training weaknesses, resulted in the Unit 1 automatic reactor trip (Sections O1.2)

Maintenance

- The inspectors concluded the documentation maintained by the licensee for the Maintenance Rule program was weak and that implementation of attributes in the process were inconsistent. The licensee had also identified these weaknesses and had identified them in the corrective action program (Section M1.2).

Engineering

- Licensee root cause reviews and engineering support for two unit trips were thorough. (Sections O1.2 and O1.3).

- A steam dump piping failure, due to a piping support modification, caused a loss of main condenser vacuum and subsequent manual reactor trip (Section O1.3).

Plant Support

- The licensee's fire protection surveillance test program for the manual hose and standpipe system did not meet all fire protection requirements as described in the UFSAR. The licensee had not provided adequate surveillance procedures to verify the functional performance of the pressure restriction valves in the manual hose and standpipe system. This was identified as a Non-Cited Violation (Section F2.1).

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at full power until May 27 when the unit automatically tripped after the 1A steam generator feedwater pump tripped. The unit was restarted on May 28 and reached full power on May 31. The unit operated at full power for the remainder of the period.

Unit 2 operated at full power until the unit was manually tripped on June 12 due to a loss of main condenser vacuum. The unit was restarted on June 15 and reached full power on June 16. The unit operated at full power for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 Routine Observations of Control Room Operations (71707 and 40500)

The inspectors observed that control room operators were attentive to annunciator alarms and promptly responded to changing plant conditions. Operator performance during two unit trips and subsequent restart activities was appropriate and effective.

O1.2 Unit 1 Automatic Reactor Trip

a. Inspection Scope (71707, 90712, 92700, and 93702)

The inspectors reviewed operator performance during post trip activities to a Unit 1 automatic reactor trip that and the licensee's post-trip root cause evaluation. The inspectors independently verified key unit parameters, operator actions, management response and oversight, and procedure implementation.

b. Observation and Findings

On May 27, operations and maintenance personnel were attempting to switch lube oil coolers on the 1A steam generator feed pump (SGFP). Because the valve to switch the lube oil coolers was stuck, additional forced was applied to open the valve. However, the valve failed when it over traveled causing a loss of lube oil pressure and a trip of the SGFP. Control room operators responded per abnormal operating procedures (AOPs) by starting all three Auxiliary Feedwater (AFW) pumps and initiating a rapid load reduction. By procedure FNP-1-AOP-17, Rapid Load Reduction, Revision (Rev.) 11, the operator was to reduce load to about 545 megawatts electric (Mwe). However, when the operator stopped the load reduction at an indicated 545 Mwe, the load reduction function continued to about 300 Mwe. The condenser steam dumps partially opened during the load reduction, but were inadequate to control reactor temperature and pressure. When reactor pressure increased to 2310 psig, a power operated relief valve (PORV) opened as expected to reduce reactor pressure. This sudden decrease in reactor pressure and the steam dumps not controlling reactor temperature resulted in the over-temperature differential temperature (OTΔT) reactor trip set point to be being exceeded which caused an automatic reactor trip.

The licensee initiated a post-trip review and determined the following: (1) The SGFP trip was caused by equipment malfunction, improper operator operation of the valve to switch lube oil coolers, poor management decision to manipulate oil coolers at full power, and weaknesses in both operating procedures and training; and, (2) The reactor trip was caused by operator error during the TG ramp down, with additional causal factors including sluggish steam dump system performance, less than adequate training on DEH response, weak AOP guidance, and the training simulator did not accurately replicate actual plant response. Licensee corrective actions included procedural enhancements, training initiatives, simulator modifications to replicate actual plant response, steam dump repairs, and inspection and caution tagging of all four SGFP lube oil transfer valves. Training included shift turnover meeting instructions, development of a training advisory notice, and operator training on the simulator after modifications were completed. In addition, the Unit 2 steam dump system was checked and repaired. The reactor was restarted on May 28 and full power was achieved May 31. The power ascension was slow and conservative due to previously identified reactor fuel and steam generator (SG) leakage.

c. Conclusion

Based on review of the licensee's root cause evaluation and independent assessments, the inspectors concluded that operator performance when switching lube oil coolers and during the load reduction, combined with procedural and training weaknesses, resulted in the Unit 1 automatic reactor trip. Licensee response was appropriate, and corrective actions appeared to be effective. The plant responded as expected to the trip with the exception of the steam dump system.

O1.3 Unit 2 Manual Reactor Trip

a. Inspection Scope (71707, 90712, 92700, and 93702)

The inspectors reviewed operator performance during post trip activities and the licensee post-trip root cause evaluation for a Unit 2 manual reactor trip. The inspectors independently verified key unit parameters, operator actions, management response and oversight, and procedure implementation.

b. Observation and Findings

On June 12, operators initiated a manual reactor trip due to a rapid decrease of main condenser vacuum. Control room operators responded promptly and stabilized the unit. The reactor was restarted on June 15 and full power was achieved on June 16. The licensee subsequently determined that a one–inch drain pipe from the condenser steam dump valves failed allowing air to leak into the condenser.

The licensee initiated a post-trip review which included a root cause evaluation. The licensee determined that piping supports installed during a 1990 modification over-restrained the drain pipe which resulted in the drain pipe fatigue failure from thermal growth.

Licensee corrective actions included modifying the piping supports, performing non destructive examinations on the similar condenser steam dump piping, repairing the failed pipe, training design personnel, and instituting a periodic monitoring program. The licensee examined Unit 1 and concluded that the piping supports do not over-restrain the drain piping due to different designs. However, the licensee plans to perform additional inspections and analyses on the Unit 1 piping.

c. Conclusion

The inspector concluded that a steam dump piping failure, due to a piping support modification, caused a loss of main condenser vacuum and subsequent manual reactor trip. Licensee response was appropriate and corrective actions were through. Operator and plant response was as expected.

O1.4 Unit 2 Steam Generator (SG) Steam Flow Channel Failures (71707)

On June 18 and 21, the Unit 1B SG steam flow channel (FT 484) failed high when the instrument piping failed. Later on June 21, the 1A SG steam flow channel (FT 475) also failed. This resulted in a SG level and feed pump transient. Operators responded by taking manual control and restoring system parameters.

The licensee initiated several ORs to document these problems, effected repairs, and returned equipment to service. The inspectors concluded that operator response was prompt and prevented a unit reactor trip.

O2 Operational Status of Facilities and Equipment

O2.1 General Tours and Inspections of Safety Systems (71707)

General tours of safety-related areas were performed by the inspectors to observe the physical condition of plant equipment and structures, and to verify that safety systems were properly maintained and aligned.

The inspectors verified the operability of selected, risk significant safety systems and equipment. These systems included the rod control systems, cold leg accumulators, residual heat removal systems, and the containment spray systems. The systems were verified to be properly aligned and maintained. The inspectors verified that selected tagouts were implemented in accordance with procedural requirements.

O2.2 Operator Work-Arounds (71707 and 40500)

The inspectors reviewed OR 2-99-240 which documented that the Unit 2 circulating water (CW) canal level unexpectedly fell from 153 feet to approximately 145 feet on May 20, 1999. The OR identified that the loss of CW canal level was due to a malfunctioning level control valve (LCV) and lack of operator attention while manually controlling CW canal level. The automatic canal level make-up valve had been disabled for several months due to actuator problems. Operators were controlling CW canal level using the manual isolation valve as a work-around. Licensee follow up identified on this OR

included a check of level every two hours, repair of the LCV, and an assessment of the operator work-around program.

The inspectors reviewed the operator work-around program, as defined by procedure FNP-0-ACP-17.0, Work-Around Program, Revision 0. The work-around list was reviewed, updated, and published monthly and contained either the expected correction date or the tracking method. The operations department was responsible to ensure current work-arounds were identified and evaluated. Since the list is published monthly, generally only long-term work-arounds were captured. By procedure, an operation supervisor reviews the monthly report to evaluate the overall impact of work-arounds. Although operations' supervision does a general review of the morning report for operator work-arounds, there is no program requirement for a review of the combined impact of short-term and long-term work-arounds. The inspectors concluded that while this specific operator work-around was poorly controlled, the program for operator work-arounds was adequate.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726 and 62707)

The inspectors witnessed or reviewed portions of the selected maintenance and surveillance test activities in progress. This included the 1A SGFP troubleshooting and lube oil cooler modifications, Unit 1 rod control system fuse testing, Unit 1 and 2 pre-startup nuclear instrumentation tests, 1A reactor makeup water pump repair, and Unit 1 and 2 power ascension tests. For those maintenance and surveillance activities observed or reviewed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders.

M1.2 Maintenance Rule Inspection

a. Inspection Scope (62707)

The inspectors reviewed the Maintenance Rule (MR) program aspects of the following five equipment failures: 2C Diesel Generator (DG) (Occurrence Report (OR) 1-99-151); 1A Reactor Make-up Water Pump (ORs 1-99-178 and 1-99-249); Unit 2 Turbine Auto Stop Trip Valves (Licensee Event Report (LER) 98-002); Unit 2 dropped control rods K-2 and F-10 (LERs 98-001-00 and 98-001-01); and, the Unit 1 Reactor Protection System (RPS) card failure (LER 98-004).

b. Observations and Findings

The MR, 10CFR50.65, requires licensees to monitor their structures, systems, and components (SSCs) against goals in order to provide reasonable assurance that the SSCs are capable of fulfilling their intended functions. Additionally, the MR requires that when the performance of these SSCs do not meet the defined goals, appropriate

corrective action should be taken. Based on the available documentation, the inspectors could not conclude that the goals for (a)(1) classified systems were being adequately updated when a new functional failure (FF) occurred. When a new FF occurred, the goals would eventually change, however, it was indeterminate whether the reason for the system to originally be classified (a)(1) had been satisfied or if the old goal was covered by the new goal.

There was an inconsistency between the corrective action (OR program and Maintenance Work Order (MWO) program) processes and the MR program. In the OR and MWO programs, the licensee did not encompass the process of determining if an event was an FF, Maintenance Preventable Functional Failure (MPFF), or a Repetitive Maintenance Preventable Functional Failure (RMPFF), as is performed in the MR program. Additionally, developing new goals or adjusting goals for monitoring (a)(1) system performance also was not addressed in the OR and MWO processes. As a result, in one case (RPS card failures), goals were not updated for more than three months after the event occurred and two months after the OR was closed. The OR and MWO programs' inconsistency with the MR program, compounded with the programmatic delay in starting the review generated by the MR program (the MR review does not start until near the end of the OR and MWO processes), caused MR goal setting and performance monitoring needed to improve system performance to be delayed.

The licensee's process of determining when a component becomes available following completion of maintenance was inconsistent. An example of this was OR 1-99-151 which was associated with a 2C DG surveillance failure. Following maintenance, the licensee performed a successful PMT and declared the DG available. When the DG surveillance test was performed the DG failed due to incorrect maintenance that had been performed. As a result, the time identified between the completion of the PMT and the surveillance test was reclassified as unavailability time rather than classifying this failure as a MPFF.

For the two cases described in LER 98-01 and LER 98-04 no determination of FF or MPFF was made. The licensee considered classifying a failure exceeding a plant level criteria, such as reactor trip or major power reduction, as more conservative than classifying the failure as a FF or MPFF. The inspectors identified that, although root cause and corrective actions could be determined and implemented with either classification (plant level criteria or MPFF), the MPFF determination still needs to be assessed in order to track reliability performance criteria for the purpose of determining repetitive MPFFs and for balancing reliability and availability.

Prior to this NRC inspection, the licensee had conducted its 1999 Maintenance Rule Periodic Assessment, which identified similar programmatic problems to those identified above. The assessment was effective in identifying and documenting the observed deficiencies and the results appear to have captured the concerns identified during this NRC inspection. The assessment findings were documented in OR 1-99-289 which had not been completed at the conclusion of this inspection.

c. Conclusion

The inspectors concluded the documentation maintained by the licensee for the Maintenance Rule program was weak and that implementation of attributes in the process were inconsistent. The licensee had also identified these weaknesses and had identified them in the corrective action program.

IV. Plant Support

F1 Control of Fire Protection Activities

F1.1 Frequency of Fire Related Incidents and Fire Reports (64704)

The inspectors reviewed plant fire occurrence reports and equipment failure work orders resulting from fire, smoke, sparks, arcing, and equipment overheating incidents for the time period of 1997-1999, to assess the effectiveness of the fire prevention program and any maintenance-related or material condition problems in accordance with procedure FNP-0-AP-30, Revision 24, "Preparation and Processing of Incident Reports, Plant Event Reports, and Licensee Event Reports," when fire-related events occurred.

The inspectors concluded that during the past three-year period, the facility's fire prevention and protection programs were effective in preventing the occurrence of significant plant fires.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Surveillance and Testing Program for the Manual Standpipe and Hose System

a. Inspection Scope (64704)

The inspectors reviewed the inspection and surveillance program and requirements from the Updated Final Safety Analysis Report (UFSAR) and conducted plant inspections of the manual hose station standpipe system to verify that the applicable components had been incorporated into the appropriate surveillance procedures. The inspectors reviewed the fire protection program requirements of UFSAR Sections 9B.4.1.9, "Manual Water Hose Stations" and 9B.6.2, "Testing Program." These UFSAR sections describe the functional components and testing requirements of the of the fire protection standpipe and manual hose station system including the pressure restriction valves.

b. Observations and Findings

During the plant tours and inspection of the standpipe and hose station system, the inspectors noted that the 1½-inch pressure restriction valves were installed downstream of the hose station isolation valve and the fire hose connection. Review of the valve manufacturer's technical manual data indicated that these devices are designed to reduce inlet fire protection water pressures from 80-175 psi down to outlet pressures of 60 or 80 psi. These valves were not being maintained in good working condition in that

some were missing the breakable links which exposed the valve spindle that adjusts the outlet pressure to the fire hose.

The Farley Facility Operating License Condition 2.C.(4) for Unit 1 and 2.C.(6) for Unit 2, states that Southern Nuclear shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR and as approved in the fire protection Safety Evaluation Reports (SERs). The Farley fire protection program as described in UFSAR Section 9.B.6.2, "Testing Program," states that fire protection equipment will be tested periodically to assure that the equipment will meet its design criteria. Appropriate testing methods and schedules will be incorporated into fire protection surveillance procedures. The testing program was implemented by procedures FNP-FSP-207, "Hose Station Flow and Operability Test," Revision 0, FNP-1-FSP-404, "Fire Hose Hydrostatic Test," Revision 3, and FNP-1-FSP-403, "Fire Hose Station Inspection,"Revision 3.

Contrary to the above, the inspectors found that these procedures did not include either routine pressure restriction valve inspection or maintenance or surveillance program performance testing for the pressure restriction valves. The failure to have adequate written surveillance procedures is a violation of the approved fire protection program as established by Farley Facility Operating License Condition 2.C.(4) for Unit 1 and 2.C.(6) for Unit 2. This NRC identified Severity Level IV violation is being treated as a Non-Cited Violation (NCV) consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as Occurrence Report #1-99-316 and is identified as NCV 50-348, 364/99-04-01, "Inadequate Procedures to Verify Manual Hose Station Pressure Restricting Valve Flow and Pressure Requirements."

c. Conclusion

The inspectors concluded that the licensee's fire protection surveillance test program for the manual hose and standpipe system did not meet all fire protection requirements as described in the UFSAR. The licensee had not provided adequate surveillance procedures to verify the functional performance of the pressure restriction valves in the manual hose and standpipe system. This was identified as a Non-Cited Violation.

F2.2 Fire Main Rupture Review (64704)

The inspectors observed and reviewed operations and engineering activities associated with a yard fire main rupture on June 16, 1999, to determine whether the licensee's compensatory measures met the fire protection program requirements.

The inspector's review concluded that the compensatory actions of the fire protection program procedures were performed following a yard fire main rupture.

F3 Fire Protection Procedures and Documentation

F3.1 Fire Brigade Pre-Fire Strategies (64704)

The inspectors reviewed fire brigade fire strategy fire zone data sheets described in UFSAR Section 9B.2.3.3.E, "Fire Fighting Procedures," for compliance with the approved fire protection program. Plant tours were also performed to verify the fire strategy fire zone data sheets for selected plant areas reflected as-built plant conditions and potential fire conditions. The inspectors reviewed the fire strategy zone data sheets for four high ranked dominant fire risk locations identified in the licensee's IPEEE.

The inspectors concluded that the fire brigade fire strategy zone data sheets met the requirements of the approved fire protection program.

F5 Fire Protection Staff Training and Qualification

F5.1 Fire Brigade Drill Program

a. Inspection Scope (64704)

The inspectors reviewed the fire brigade drill program to assess the response time and performance of the fire brigade during drills in risk significant plant areas and compliance with plant procedures and NRC.

b. Observations and Findings

The inspectors reviewed the plant IPEEE risk assessment submitted to the NRC on June 25 1995, and the list of areas in which fire drills had been held during the past 5-year period. The inspectors noted that a fire drill had not been performed since 1995 in the Electrical Switchgear Rooms (Fire Areas 21 and 41); the Auxiliary Building Switchgear Rooms (Fire Areas 18 and 19); Diesel Generator Building Switchgear Rooms (Fire Areas 56A and 56B); the Electrical Penetration Rooms (Fire Areas 34 and 35); Component Cooling Water Pumps Room (Fire Area 6); or the Control Room (Fire Area 44A). These plant areas were identified in Section 4.10 of the IPEEE as the most risk significant plant areas with a combined total of greater than 85% of the total fire induced core damage frequency (CDF). This was considered a fire brigade drill program weakness in that drills in various risk significant plant areas were not performed in the past five years to assure that the brigade was familiar with the fire protection, operational features, and fire hazards identified in the fire zone data sheets for these risk significant areas.

c. Conclusion

The fire brigade response time and performance as documented by drill evaluations met the requirements of plant procedures. A fire brigade drill program weakness was identified in that fire brigade drills had not been performed since 1995 in some risk significant areas of the plant.

F8 Follow-up on Plant Support Items (92904)

F8.1 (Closed) IFI 50-348,364/97-12-01: Review of Engineering Evaluations to Establish the Fire Ratings of Silicone Foam Penetration Seals.

This item was opened pending additional review of vendor qualification test report and engineering evaluation documentation to support silicone foam penetration seal installations at Farley. The inspectors reviewed engineering evaluations for four silicone foam penetration seal configurations and determined that the fire barrier penetration designs were properly supported by the enhanced seal design basis documentation.

Based on this review, this item is considered closed.

R2 Status of Radiological Protection Facilities and Equipment

R2.1 Radiologically Controlled Area (RCA) Tour (71750)

Overall cleanliness of the RCA remained good. Plant personnel observed working in the RCA generally demonstrated appropriate knowledge and application of radiological control practices. Health physics technicians generally provided positive control and support of work activities in the RCA.

S1 Conduct of Security and Safeguard Activities

S1.1 Routine Observations of Plant Security Measures (71750)

The inspectors verified that portions of site security program plan was being properly implemented. Disabled vital area doors were properly manned and controlled. Security personnel activities observed during the inspection period were performed well. Site security systems were adequate to ensure physical protection of the plant.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on July 8. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

Partial List of Persons Contacted

Licensee

R. V. Badham, Safety Audit Engineering Review Supervisor
R. M. Coleman, Maintenance Manager
K. C. Dyar, Security Manager
T. H. Esteve, Planning and Control Superintendent
R. S. Fucich, Engineering Support Manager
S. Fulmer, Plant Training and Emergency Preparadness Manager
J. S. Gates, Administration Manager
D. E. Grissette, Assistant General Manager - Operations
J. G. Horn, Outage Planning Supervisor
J. R. Johnson, Operations Manager
C. D. Nesbitt, Assistant General Manager - Plant Support
L. M. Stinson, Plant General Manager - FNP
R. J. Vanderbye, Emergency Prepardness Coordinator
G. S. Waymire, Technical Manager
B. R. Yance, Plant Modification and Maintenance Support Manager

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, mechanics, and electricians.

Partial List of Opened, Closed, and Discussed Items

Type	Item Number	Status	Description and Reference
NCV	50-348,364/99-04-01	Closed	Inadequate Procedures to Verify Manual Hose Station Pressure Restricting Valve Flow and Pressure Requirements (Section F2.1)
IFI	50-348,364/97-12-01	Closed	Engineering Evaluations for Fire Ratings (Section F8.1)
LER	50-348/99-02	Closed	Unit 1 automatic reactor trip (Section O1.2)
LER	50-364/99-01	Closed	Unit 2 manual reactor trip (Section O1.3)

List of Inspection Procedures (IP) Used

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Prevent Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations

IP 64704:	Fire Protection Program
IP 71707:	Plant Operation
IP 71750:	Plant Support Activities
IP 90712:	Inoffice Review of Written Reports
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92904:	Follow-up Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors