UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

EA-01-165

Southern Nuclear Operating Company, Inc.
ATTN: Mr. D. N. Morey
Vice President
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 50-348/01-02 and 50-364/01-02

Dear Mr. Morey:

On June 30, 2001, the NRC completed an inspection at your Farley Nuclear Plant. This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. The enclosed report documents the inspection findings which were discussed on July 6, 2001, with Mr. Mike Stinson and other members of your staff.

Based on the results this inspection, the inspectors identified four findings of very low safety significance. One of these findings was determined to be a violation of NRC requirements. However, because of its very low safety significance and because you have entered it into your corrective action program, the NRC is treating this violation as a Non-Cited Violation in accordance with Section VI.A.I of the NRC's Enforcement Policy.

If you deny this non-cited violation, you should provide a response with the basis of your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at the Joseph M. Farley Nuclear Plant.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be publicly available in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at *http://www.nrc.gov/NRC/ADAMS/index.html* (the Public Electronic Reading Room).

Sincerely,

Curt Rapp for

Stephen J. Cahill, Chief
Reactor Projects, Branch 2
Division of Reactor Projects

Docket Nos. 50-348 and 50-364
License Nos. NPF-2 and NPF-8

Enclosure: NRC Integrated Inspection
Report 50-348/01-02 and 50-364/01-02

Attachment: 1. List of Documents Reviewed cc w/encl:

M. J. Ajluni, Licensing
Services Manager, B-031
Southern Nuclear Operating
Company, Inc.
Electronic Mail Distribution

L. M. Stinson
General Manager, Farley Plant
Southern Nuclear Operating
Company, Inc.
Electronic Mail Distribution

J. D. Woodard
Executive Vice President
Southern Nuclear Operating
Company, Inc.
Electronic Mail Distribution

State Health Officer
Alabama Department of Public Health
RSA Tower - Administration
Suite 1552
P. O. Box 303017
Montgomery, AL 36130-3017

M. Stanford Blanton
Balch and Bingham Law Firm
P. O. Box 306
1710 Sixth Avenue North
Birmingham, AL 35201

Rebecca V. Badham
SAER Supervisor
Southern Nuclear Operating Company
Electronic Mail Distribution

Distribution w/encl:
F. Rinaldi, NRR
RIDSNRRDIPMLIPB
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SIGNATURE	TPJ		SJC2	SJC2 per e-mail	JJB1	DBF	SJC2 per e-mail
NAME	TJohnson	RCaldwell	SStewart	JCanady	JBlake	DForbes	RGibbs
DATE	07/19/2001	7/ /2001	07/19/2001	07/20/2001	07/20/2001	07/23/2001	7/26/01
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

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U. S. NUCLEAR REGULATORY COMMISSION (NRC)

REGION II

Docket Nos.:	50-348 and 50-364
License Nos.:	NPF-2 and NPF-8
Report Nos.:	50-348/01-02 and 50-364/01-02
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	Farley Nuclear Plant, Units 1 and 2
Location:	7388 N. State Highway 95 Columbia, AL 36319
Dates:	April 1, 2001 to June 30, 2001
Inspectors:	T. Johnson, Sr. Resident Inspector (SRI) R. Caldwell, Resident Inspector (RI) S. Stewart, SRI Crystal River J. Canady, RI North Anna D. Forbes, Radiation Specialist (Sections 2PS1and 2PS3) J. Blake, Sr. Project Manager (Sections 1R08 and 4OA5.3) R. Gibbs, Sr. Reactor Engineer (Sections 1R12.3 and 4AO2)
Approved by:	Stephen J. Cahill, Chief Reactor Projects, Branch 2 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000348/01-02, IR 05000364/01-02, on 04/01/2001-06/30/2001, Southern Nuclear Operating Company, Joseph M. Farley Nuclear Plant, Units 1 & 2, maintenance rule.

This integrated inspection report covers a 13-week period of inspection conducted by resident inspectors two visiting resident inspectors, a regional radiation specialist, and two regional maintenance inspectors. The inspectors identified one Green finding and three No Color findings. One No Color finding is a non-cited violation. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated "No Color" or by the severity of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at *http://www.nrc.gov/NRR/OVERSIGHT/index.html*.

A. Inspector Identified Findings.

Cornerstone: Initiating Events

- Green. The inspectors identified that the licensee did not effectively determine the root cause of Unit 2 Main Steam (MS) piping vibrations. This resulted in recurring failures of the MS piping supports since October 1983.

  The issue is of more than minor safety significance because if left uncorrected, the potential for a main steam line break could be increased. However, this finding is of very low safety significance because analyses of the piping surface damages showed them to be superficial and stress analyses of the affected piping showed that, without the damaged supports and with the maximum piping deflection, code allowable stresses were not exceeded (Section 1R08).

- No Color. A Non-cited Violation of 10CFR50.65(b)(2)(iii) was identified for failing to include the function of the circulating water canal make-up valves in the Maintenance Rule program scope. The inspectors found that failures of these valves had resulted in cavitation of the Circulating Water pumps and loss of main condenser vacuum.

  This finding is of more than minor safety significance because failure of these valves has resulted in a loss of normal heat removal which could initiate a reactor trip. However, this finding is of very low safety significance because no actual reactor trips occurred from failures of these valves (Section 1R12.1).

- No Color. The inspectors identified that the licensee did not develop Maintenance Rule unavailability performance criteria for steam generator water level control, a safety-related risk significant system function.

  This finding is of more than minor safety significance because performance monitoring criteria is necessary to balance the reliability and availability of this risk significant function. However, this finding is of very low safety significance because there have been no failures of this function (Section 1R12.1).

Cornerstone: Mitigating Systems

- No Color. The inspectors identified that many corrective actions for Maintenance Rule issues have not been timely and effectively implemented. The finding was based on the inspectors review of the 2001 Maintenance Rule periodic assessment which identified several Maintenance Rule problems that have gone uncorrected for several years.

  This finding does have a credible impact on safety because Maintenance Rule issues left uncorrected could result in increased plant equipment problems, equipment unavailability, or initiating event frequency. This finding was considered to be of very low safety significance because no direct consequences have occurred due to the uncorrected problems (Section 1R12.2 and Section 4OA2).

B. <u>Licensee Identified Violations</u>

None.

Report Details

Summary of Plant Status

Unit 1 operated at 100% rated thermal power (RTP) until June 2 when power was reduced to 70% RTP to repair a main condenser tube leak. On June 3, power was reduced to about 67% RTP when main condenser vacuum decreased due to failure of the circulating water canal level control valve. Power was increased to 100% RTP on June 6 where it remained for the remainder of the report period.

Unit 2 remained in a steam generator replacement and refueling outage until May 7. The unit reached 100% RTP on May 15 and remained at 100% RTP until June 23 when a turbine trip and reactor trip occurred when a generator protection relay lost power. The unit was restarted and reached 100% RTP on June 25. On June 26, the reactor tripped again when a switch in the main control room was replaced. The unit was restarted and reached 100% RTP on June 27 where it remained for the remainder of the report period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather

a. Inspection Scope

The inspectors reviewed the licensee's adverse weather preparations for both the Component Cooling Water and Service Water systems. The inspectors assessed if Procedure FNP-0-AP-21.0, Severe Weather, adequately addresses actions and compensatory measures for site and plant conditions and equipment affected by possible high temperature conditions and for tornado and hurricane events. The Updated Final Safety Analysis Report (UFSAR), Individual Plant Examination (IPE) and IPE of External Events (IPEEE) Reports, plant procedures, and drawings were reviewed to ensure that the systems, structures, and components would remain functional during adverse weather conditions. The inspectors verified if the licensee had appropriately identified and corrected deficiencies that could affect the plant's ability to cope with adverse weather conditions.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial System Walk Downs

a. Inspection Scope

The inspectors performed partial system walk downs to verify that the systems listed below were properly aligned when redundant systems or trains were out of service as required by licensee procedures FNP-0-AP-16, Conduct of Operations - Operations Group and FNP-0-SOP-0, General Instructions to Operations Personnel. The walk down included a review of the UFSAR, plant procedures and drawings, and control room and infield checks of valves, switches, components, electrical power line-ups, support equipment, and instrumentation.

- Unit 2 Residual Heat Removal System
- Unit 1 Emergency AC power
- Unit 2 Emergency AC power

b. Findings

No findings of significance were identified.

.2 Complete System Walk Down

a. Inspection Scope

The inspectors performed a complete system walk down of the Unit 1 and 2 Service Water (SW) systems to verify that these systems were properly aligned in accordance procedure FNP-1(2)-SOP-24, SW System. The walk down included a review of plant normal operating and abnormal/emergency operating procedures, Technical Specifications, drawings, design documents, Functional System Descriptions, vendor manuals, and the UFSAR. The inspectors conducted control room and infield checks of valves, switches, components, electrical power line-ups, support equipment, and instrumentation. In addition, open maintenance work orders, outstanding design issues, operator work arounds, temporary modifications, hangers and supports, general area housekeeping, and material conditions were reviewed to verify that the licensee was identifying and correcting system deficiencies.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted a walk down of six fire areas located in the auxiliary, diesel, and service water buildings to verify the licensee's implementation of fire protection requirements as described in licensee procedures FNP-0-AP-36, Fire Surveillance and Inspection, FNP-0-AP-37, Fire Brigade Organization, FNP-0-AP-38, Use of Open Flame, and FNP-0-AP-39, Fire Patrols and Watches. The specific fire areas were zones 72A, 61, 191, 2192, 131, and 185. The inspectors verified the licensee's control of transient combustibles, the operational readiness of the fire suppression system, and the material condition and status of fire dampers, doors and barriers. The inspectors also verified that adequate compensatory measures, including fire watches, were in place for degraded fire barriers. The inspectors compared the requirements in the UFSAR Appendix 9B, Fire Protection Program, to the licensee's implementing procedures.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed flood protection measures as required by abnormal operating procedure FNP-0-AOP-21.0, Severe Weather. The inspectors walked down the CCW pump and heat exchanger rooms, Emergency Diesel Generator (EDG) Building, SW Building, Turbine Building, Main Steam valve rooms, Containment Spray pump rooms and RHR pump and heat exchanger rooms and checked for room sealing, watertight doors, drainage and sump systems, and any potential sources of flooding. For those plant areas credited with operator actions, emergency and abnormal operating procedures were reviewed. The internal flooding analysis and plant design features described in the UFSAR were used as criteria for this inspection. The inspectors also reviewed the documents listed in Attachment 1.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

a. Inspection Scope

During licensee inspections on February 26, 2001, of the Unit 2 Main Steam (MS) system inside containment, all three steam line supports were found to be damaged. Subsequent inspections of the steam lines found indentations on the piping from contact with whip restraints and wear marks from contact with the stainless steel mirror insulation. Additional damaged steam line supports and support components were identified in the MS valve room and in the turbine building indicating a common cause failure. These conditions were documented in Condition Reports (CRs) 2001000525, 2001000555, and 2001000704. The inspectors reviewed the licensee's inspections, evaluations, and corrective actions for the damage to the Unit 2 steam lines and supports.

b. Findings

A finding of very low safety significance (Green) was identified for not effectively determining the root cause(s) of excessive Unit 2 Main Steam (MS) piping vibrations. Previous MS line support failures, dating back to the second refueling outage in October 1983, were corrected by redesigning and strengthening damaged supports without fully determining the root cause of the piping vibrations. This resulted in recurring failures of piping supports.

The damaged MS supports inside containment were SCS-2H220, 2MS-R98 and 2MS-R89/90. SCS-2H220 was a replacement for supports 2MS-R84 and 2MS-R85 which started showing evidence of vibration induced failures during the second refueling outage in October 1983. Failures and repairs were again recorded in the fourth, fifth, and sixth refueling outages before the original supports were replaced by SCS-2H220 during the ninth and tenth refueling outages. SCS-2H220 was found to be damaged and was strengthened during the recent fourteenth refueling outage.

Supports 2MS-R98 and 2MS-R89/90 were found to have cracks in structural welds between vertical and horizontal members during the fourth refueling outage in April 1986. During the fifth refueling outage in October 1987, support 2MS-R89/90 was again found to have cracks in structural welds and was once again repaired. Repairs and redesign of these supports apparently lasted until they were found to be damaged and repaired during the recent fourteenth refueling outage.

The licensee's documentation of repair activities since the second refueling outage in October 1983, indicated that the licensee's root cause determinations went as far as determining that the MS support failures were indicative of low cycle, high stress fatigue, caused by excessive movement of the MS lines during operation of the plant, but did not effectively determine the cause of the excessive vibration. The inspectors reviewed calculations TE-BS-01-2440-001, -002, and -003, which were special stress analyses of the MS piping inside containment. The calculations showed that without the damaged supports, and with the maximum deflection from the vibrations, including those during a postulated safe shutdown earthquake, the MS piping stresses did not exceed the code allowable stresses.

This finding is of more than minor safety significance because the root cause of the vibration has not been determined which created the potential for additional piping support failures which could increase the frequency of a steam line break. This finding was considered to be of very low safety significance because stress analyses of the affected piping showed that without the damaged supports and with the maximum deflection of the vibration, code allowable stresses were not exceeded. (Green)

During the recent fourteenth refueling outage, the licensee established a project to fully instrument the Unit 2 MS lines to determine the cause of the excessive vibration and to define appropriate permanent modifications prior to the next refueling outage in the Fall of 2002. Vibration dampening devices were attached to the MS lines to minimize the effects of the vibrations in the interim. Licensee CR 2001000389 documented the damaged supports inside containment and will track the corrective actions.

The inspectors confirmed the licensee's determination that the scratches and contact indications documented in CRs 2001000525 and 2001000555 were acceptable through comparison with the acceptance requirements of the fabrication code, ASME, Section III, 1971 edition with Summer 1971 addenda. The inspectors verified the licensee's evaluation that the bulge and UT indications were determined to be fabrication defects through review of a metallurgical report.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

The inspectors observed portions of the licensed operator training and testing program per procedure FNP-0-AP-45, Farley Nuclear Plant Training Program. The inspectors observed operator training scenarios for a station blackout, a small break loss of coolant accident, a main steam isolation and unit trip, and a steam generator tube rupture. The inspectors assessed high risk operator actions, overall performance, self-critiques, training feedback, and management oversight.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

.1 Equipment Monitoring

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of functional failures, maintenance preventable functional failures, repetitive failures, availability and reliability monitoring, and system specialist involvement. The inspectors interviewed maintenance personnel, system specialists, the Maintenance Rule (MR) coordinator, and operations personnel. The following equipment was evaluated for compliance with 10 CFR 50.65 and licensee procedures FNP-0-M-87, Maintenance Rule Scoping Manual, FNP-0-SYP-19, Maintenance Rule Performance Criteria, FNP-0-M-89, and the FNP Maintenance Rule Site Implementation Manual:

- Unit 1 TDAFW pump
- 4160 volt breakers
- 600 volt load center breakers
- Unit 2 AFW system
- Unit 1 & 2 Circulating Water Make-Up Valves
- Feed Water Control System

b. Findings

The inspectors identified a no color finding which was a Non-Cited Violation of 10 CFR 50.65(b)(2)(iii) for failure to scope the function of the Unit 1 & 2 circulating water canal make-up valves in the MR program. . The inspectors identified a second no color finding because the licensee had not established unavailability performance criteria for steam generator level control which was designated as a risk significant function.

Normal CW canal level was maintained at approximately 153 feet by Service Water valves Q1-P16-V560 and Q2-P16-V560. Failures of these valves have resulted in near-miss reactor trip initiators on two occasions. The first event occurred on May 20, 1999, when the Unit 2 CW canal level fell to 145 feet. The level control valve had been disabled for several months due to actuator problems and operators were controlling CW canal level using the manual isolation valve. This event was documented in OR 2-99-240. The second event occurred on June 3, 2001, when the Unit 1 CW canal level decreased to less than 140 feet causing cavitation of the circulating water pumps and decreasing main condenser vacuum. Operators reduced Unit 1 power as a precaution if a CW pump had to be tripped and to restore condenser vacuum. Since Unit 1 was operating at only 70% RTP, main condenser vacuum did not decrease sufficiently to require a reactor trip. This event was documented in CR 2001001349.

These valves have failed on several other occasions, but did not challenge plant operation. The Unit 1 CW canal make-up valve failed on December 15, 2000, (CR 2000005571) and December 19, 2000, (CR 2000005571). The Unit 2 CW canal make-up valve failed on December 20, 2000 (CR 2000005917). These previous failures were addressed through normal work control processes and by the licensee's work-around program.

The inspectors reviewed the Maintenance Rule (MR) scoping for both the Circulating Water System and the Service Water System and determined that the function of the Unit 1 & 2 CW canal make-up valves was not included. This finding is of more than minor safety significance because failure of these valves has resulted in a loss of normal heat removal which could initiate a reactor trip. However, this finding is of very low safety significance because no actual reactor trips occurred from failures of these valves. Because this MR process finding could not be evaluated using the SDP, it is a No Color finding.

10 CFR 50.65(b)(2)(iii) requires non-safety related structures, systems, or components whose failure could cause a reactor trip, to be in the scope of the monitoring program. This violation is being treated as a Non-Cited Violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 348, 364/2001-02-01, Inadequate Maintenance Rule Scoping. This violation is in the licensee's corrective action program as a part of CR 200100200753.

The second No Color finding concerns Maintenance Rule function C22A, Control of Steam Generator Level. The inspectors reviewed the MR functions in FNP-0-M-87, Maintenance Rule Scoping Manual and found that function C22A was designated as a risk significant function of the Feed Water Control System. However, no performance monitoring criteria was established for function C22A in FNP-0-SYP-19, Performance Criteria For Systems Under The Scope Of The Maintenance Rule. NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power

Plants, states that risk significant functions will be monitored for reliability and availability. NUMARC 93-01 was endorsed by Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance At Nuclear Power Plant.

This finding is of more than minor safety significance because performance monitoring criteria is necessary to balance the reliability and availability of this risk significant function. However, this finding is of very low safety significance because there have been no failures of this function. This finding is in the licensee's corrective action program as CR 200100200753. This finding did not constitute a violation of NRC regulations.

.2 Review of Periodic Assessment

a. Inspection Scope

The inspector reviewed the licensee's periodic assessment, "Plant Farley Maintenance Rule Periodic Assessment-January, 2001", dated March 9, 2001, which was issued in accordance with paragraph 10 CFR 50.65(a)(3) (the Maintenance Rule). The inspector reviewed the assessment to determine that the assessment included all required areas including balancing reliability and unavailability, review of (a)(1) activities, review of (a)(2) activities, and consideration of industry operating experience. The inspector reviewed the goals and monitoring for a sample of (a)(1) structures, systems and components (SSCs), to assess if appropriate changes were made in (a)(2) SSC performance criteria, and to assess if balancing of reliability and availability met the industry guidance. The inspector reviewed the effectiveness of problem identification and resolution as related to Maintenance Rule issues.

b. Observations and Findings

One No Color finding was identified in that resolution for several Maintenance Rule issues has not been timely and effectively implemented. The results of the licensee's 2001 Maintenance Rule periodic assessment identified Maintenance Rule problems that, in many cases, have gone uncorrected for several years.

The 2001 assessment noted that timeliness for completion of corrective actions for (a)(1) SSCs was identified as a problem in the 1999 assessment and continued to be a problem. The 2001 assessment noted that corrective actions had been completed for only five of the twenty-five SSCs listed in the December 2000 monthly status report in category (a)(1). Many of these SSCs were classified as (a)(1) in 1995 or 1996 and corrective actions had still not been completed. In some cases, SSCs are not being monitored against goals until corrective actions are complete. Many of the (a)(1) SSCs had multiple problems which had contributed to performance deficiencies and previous White NRC Performance Indicators for equipment availability.

The 2001 assessment also noted that System Specialist knowledge of fundamental Maintenance Rule concepts remained low. Confusion existed concerning the difference between goals and corrective action, and risk significance and non risk significance for Maintenance Rule activities. As a result, established goals were not always specific to the failure mechanism, goals contained a single criterion for verification although many of these items had multiple failures, the consideration of risk worth in establishment of goals was not documented, and the use of industry operating experience was not incorporated in establishing goals for (a)(1) SSCs. The 2001 assessment noted that four recommendations from the licensee's 1999 assessment related to providing additional guidance and training for system owners had not been resolved.

The assessment determined that the following concerns identified in NRC Supplemental Inspection Report 50-348, 364/00-11 for White Performance Indicators, remained uncorrected and were not clearly scheduled for resolution:

- The licensee has not completed re-scoping all SSCs under the Maintenance Rule to scope by function rather than by system.
- The licensee's Maintenance Rule program did not include monitoring for approximately fifty SSCs which were identified as risk significant in both the current revision and previous revisions of the Probabilistic Risk Assessment (PRA).

The inspector concluded that the 2001 periodic assessment fully met the MR requirements for assessment. However, resolution for several Maintenance Rule issues was not being effectively completed. The inspector noted that actions were taken after the 2001 assessment to place the identified problems from both the 1999 and 2001 assessments into the corrective action program and CR 2001000658 was issued.

This finding does have a credible impact on safety because Maintenance Rule issues left uncorrected could potentially result in increased plant equipment problems, equipment unavailability, or initiating event frequency. For example, the licensee previously experienced a White Performance Indicator for equipment unavailability involving circuit breakers which had remained in category (a)(1) for over five years (NRC Inspection Report 50-348, 349/00-08). However, this finding was considered to be of very low safety significance because no actual consequences have occurred. This finding did not constitute a violation of NRC regulations or requirements.

1R13 <u>Maintenance Risk Assessments and Emergent Work Control</u>

a. <u>Inspection Scope</u>

The inspectors assessed licensee activities against the requirements in procedures FNP-0-ACP-52.1, Guidelines for Scheduling of On-Line Maintenance, AP-FNP-0-AP-52, Equipment Status Control and Maintenance Authorization, and FNP-0-AP-16. The inspectors reviewed the licensee's planning and control of these work activities and to assess if the licensee had adequately identified and resolved risk challenges for emergent work for the following systems:

- 1-2A Emergency Diesel Generator 9 month PM
- 2B Residual Heat Removal Pump
- 2E SW pump motor replacement
- 2B EDG 18 month overhaul and loss of one off site power supply
- Unit 1 SSPS power supply maintenance
- Unit 2 condenser inspections and cleaning

b. <u>Findings</u>

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Evolutions

a. Inspection Scope

The inspectors observed the licensee's response to a Unit 2 reactor trip on June 23 and subsequent start-up on June 24 and a Unit 2 reactor trip and subsequent start-up on June 26. These observations included main control room command and control, procedure usage, event notification, reactor trip data gathering, root cause team investigation, and portions of the start-up. The inspectors verified if these activities were completed in accordance with the following procedures: FNP-0-AP-16; FNP-0-ACP-9.1, Root Cause Investigation; FNP-0-EIP-8.0, Reactor Plant Event Notification; FNP-2-EEP-0, Reactor Trip or Safety Injection; FNP-2-ESP-0.1, Reactor Trip Response; FNP-2-UOP-2.1, Shutdown of Unit From Minimum Load to Hot Standby; FNP-2-STP-29.6, Calculation of Estimated Critical Condition; and FNP-2-UOP-1.3, Start-up of Unit Following an At Power Reactor Trip.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the licensee's operability evaluations to assess the technical adequacy, consideration of degraded conditions, and identification of compensatory measures. Inspectors reviewed the evaluations against the design bases as stated in the UFSAR and Functional System Descriptions. The licensee's evaluations were compared to the requirements of licensee procedures FNP-0-AP-16 and FNP-0-ACP-9.2, Operability Determination, for the following systems:

- OD-01-02, 1B EDG Small Load Swings at Low Load
- OD-01-04, Westinghouse 600 volt load center breakers
- OD-01-05, 2B EDG Jacket Water Leakage

b. Findings

No findings of significance were identified.

1R16 Operator Work Arounds

a. Inspection Scope

The inspectors reviewed operator work arounds to assess if system functional capability or human performance were affected. The inspectors reviewed the cumulative effects of the operator work arounds on the operators' ability to implement abnormal or emergency operating procedures, potential to increase an initiating event frequency, and potential to affect multiple mitigating systems. Additionally, the prioritization and actions required to address the operator work arounds as required by licensee procedure FNP-0-ACP-17, Operator Work Arounds, were evaluated for the following systems:

- Reactor water makeup automatic flow control reset function (Units 1 and 2)
- DEHC control when turbine is in manual (Unit 1)
- Service Water (Unit 1 leak; Unit 2 Dilution bypass valve failed closed)

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors used licensee procedures FNP-0-ACP-52.1, Guidelines for Scheduling of On-Line Maintenance, and AP-FNP-0-AP-52, Equipment Status Control and Maintenance Authorization, to verify that post maintenance test procedures and test activities were adequate to verify system operability and functional capability for the following systems:

- 2B Containment Spray Pump (per FNP-0-MP-84.0 and WO 0662284)
- FNP-0-MP-14.20, Emergency Diesel Generator 1-2A, 1B, and 2B Nine Month Inspection
- 1-2A EDG
- 2B EDG
- Unit 1 AFW
- Unit 1 SSPS power supply replacement

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors reviewed the following activities related to the Unit 2 refueling outage and steam generator replacement project (SGRP) for conformance to licensee procedures FNP-0-UOP-4.0, General Outage Operations Guideline, and FNP-2-UOP-4.1, Refueling Outage Operation. Surveillance tests were reviewed to verify results were within the TS required specification. Shut down risk, management oversight, and operator awareness were evaluated for each of the following activities:

- SGRP activities
- Initial criticality and reactor startup testing (FNP-2-STP-101, Zero Power Reactor Physics Testing, and FNP-2-ETP-4462, Unit 2 - Power Ascension Following Steam Generator Replacement)
- Core reload refueling operations (Westinghouse Unit 2 Cycle 14 Core Reload Manual)

- Outage-related surveillance tests (FNP-2-STP-45.7, MSIV and Bypass Valves Inservice Test, FNP-2-STP-21.1, Main Steam Line Isolation Valve Inservice Test, and FNP-0-ETP-3616, Flux Map Data Collection)
- Reactor coolant drain down and reduced inventory activities (FNP-2-SOP-1.5, Draining the RCS)
- Mode changes (FNP-2-UOP-1.2, Startup of Unit from Hot Standby to Minimum Load, and FNP-2-SOP-28.1, Turbine Generator System Startup)
- Westinghouse procedure EN 2.4.1 APR-1, Reactor Vessel Head Penetration Video Inspection for J.M. Farley Unit 2

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors used licensee procedures FNP-0-AP-24, Test Control, FNP-0-M-050, Master List of Surveillance Requirements, and FNP-0-AP-16 to verify system and component operability. The inspectors also verified that the acceptance criteria for the following surveillance test procedures met Technical Specification (TS) and design requirements:

- FNP-2-STP-16.2, 2B Containment Spray Pump Quarterly Inservice Test
- FNP-1-STP-80.1, Diesel Generator 1B Operability Test
- FNP-1-STP-109, Power Range Neutron Flux Channel Calibration Using the Plant Computer
- FNP-2-STP-11.2, 2B Residual Heat Removal Pump Quarterly Inservice Test
- FNP-2-STP-40.2, B2G and B2J Sequencer Load Shedding Test
- FNP-2-STP-80.15, DG B LOSP Test
- FNP-2-STP-80.1, Diesel Generator 2B Operability Test

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed open temporary modifications, referred to as Minor Departure (MD), including the 10 CFR 50.59 screening criteria against the system design bases information and documentation. The inspectors reviewed MD implementation, configuration control, post-installation test activities, drawing and procedure updates, and operator awareness for the following MDs:

- MD 00-02630, Unit 1 Nuclear Instrument N36 Signal Cable
- MD 00-02635, 2636, and 2648, Unit 1 Cooling Towers Temporary Repairs
- MD 01-02656 and 2662, Removal of Unit In Cores H13, C12, and C4 From Service
- MD 01-02657, 2B SGFP Nozzle Block Steam Leak Furmanite Repair

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Public Radiation Safety (PS)

2PS1 Radioactive Gaseous and Liquid Effluent Monitoring Systems

.1 Effluent Release Processing

a. Inspection Scope

Farley laboratory quality control (QC) program activities for liquid and airborne sample radionuclide analyses were evaluated. The inspectors discussed and reviewed, as applicable, current gamma spectroscopy and liquid scintillation detection equipment calibrations and daily system performance results. The inspectors also evaluated preparation, processing and storage of composite samples, radionuclide concentration lower level of detection (LLD) capabilities and achieved accuracies, and results of the quarterly cross-check spiked radionuclide samples analyzed during calendar year 2000.

The inspectors reviewed and discussed Quality Assurance (QA) Report VI.3 dated May, 01, 2001, for laboratory gamma counting equipment. The offsite effluent dose results as reported in the April 26, 2001, Annual Radiological Effluent Release Report were evaluated against 10 CFR Part 20 requirements, Appendix I to 10 CFR Part 50 design criteria, TS, UFSAR details, and the Offsite Dose Calculation Manual (ODCM), Revision (Rev.) 20. A liquid release permit 10329.022.085.L for a Unit 2 Waste Monitor tank release and a gaseous release permit 10144.027.024.G for a plant vent stack release were evaluated against ODCM requirements and appropriate alarm setpoints. The inspectors also evaluated an unplanned release of gaseous effluents that occurred on May 26, 2001, as the result of a Unit 2 flow control valve packing leak in order to verify licensee calculations for quantifying the release.

b. Findings

No findings of significance were identified.

.2 Airborne Effluent Vent Flow and Air Cleaning System Surveillance

a. Inspection Scope

The inspectors evaluated current surveillance activities for filtration testing of Penetration Rooms, Control Room Emergency Ventilation, and Post Accident Containment Ventilation systems. Surveillance activities were reviewed against TS, UFSAR, American Nuclear Institute Standard N510, 1989, Testing of Nuclear Air-Cleaning Systems; and Regulatory Guide (RG) 1.52, Design, Testing and Maintenance Criteria for Post Accident Engineered Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants, Rev. 2. The following procedures were reviewed and discussed:

- Farley Nuclear Plant Surveillance Test Procedure FNP-1-STP-124.0A, A-Train Penetration Room Performance Test, Version 5.1
- Farley Nuclear Plant Surveillance Test Procedure FNP-1-STP-124.0B, B-Train Penetration Room Performance Test, Version 6.1
- Farley Nuclear Plant Surveillance Test Procedure FNP-1-STP-123.0, Control Room Emergency Ventilation Performance Test, Revision 18
- Farley Nuclear Plant Engineering Test Procedure FNP-2-ETP-4446, Post Accident Containment, Revision 1

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring and Radioactive Material Control Program

.1 Radiological Environmental Monitoring Program (REMP) Implementation

a. Inspection Scope

REMP sampling quality control (QC) activities for selected sample types listed in the 2000 Annual Radiological Environmental Monitoring Report dated April 26, 2001, were reviewed and evaluated. Evaluated QC activities included assessment of trends for reported inter-laboratory comparison results; verification of LLD capabilities for selected gamma emitting radionuclides in fish, gross beta analyses for particulate sample filters, and tritium analyses for surface water analyses; and collection and preservation of surface water samples. The inspectors also verified pump flow calibrations and airflow determinations for selected particulate and charcoal airborne sampling systems.

The REMP QC activities were reviewed against RG 4.1, Programs for Monitoring Radioactivity in the Environs of Nuclear Power Plants, Rev 1, April 1975, and RG 1.21, Measuring, Evaluating and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials In Liquid and Gaseous Effluents from Light-Water Cooled Nuclear Power Plant, June 1974. Program implementation and sample monitoring activities were verified against TS, ODCM Rev. 20, and the CY 2000 Annual Environmental Monitoring Report details. The inspectors reviewed and evaluated the use of licensee procedure FNP-0-IMP-255.2, Environmental Air Monitoring Station Preventive Maintenance and Calibration, Rev. 4.

b. Findings

No findings of significance were identified.

.2 Controls for Unrestricted Release of Material from the Radiologically Controlled Area (RCA)

a. Inspection Scope

Licensee guidance and program implementation for monitoring potentially contaminated material for unrestricted release from the RCA were reviewed and evaluated. The evaluation included current direct monitoring activities and recent licensee initiatives to evaluate hard-to-detect radionuclides. Availability and accuracy of survey instruments used for release, e.g., friskers, proportional counters, and small article monitors, were verified for RCA control points. In-service Instrumentation calibration records and alarm setpoints were evaluated and discussed. The inspectors observed routine release survey activities.

Licensee activities were evaluated against 10 CFR Part 20 requirements and UFSAR details. Established detection limits were reviewed against guidance provided in NRC Circular 81-07 and Information Notice 85-92 and licensee procedure FNP-0-RCP-29, Contamination Guidelines, Version 34.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors used licensee procedure FNP-0-AP-54, Preparation and Review of NRC Performance Indicator Data and the Technical Specifications, to verify the second quarter of 2001 PI data for Unplanned Scrams, Scrams with a Loss of Normal Heat Removal, and Unplanned Power Changes in the initiating Events Cornerstone, and Emergency AC Power System Unavailability and Heat Removal System (AFW) Unavailability in the Mitigating Systems Cornerstone. The inspectors reviewed portions of Unit 1 and Unit 2 Operator Logs for January and March, 2001, the daily morning reports (including the daily CR descriptions), the monthly operating reports, Licensee Event Reports (LER), NRC Inspection Reports, and several TS Limiting Conditions of Operation (LCO's). The inspectors also interviewed licensee personnel associated with the PI data collection, evaluation and distribution.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution

Section 1R12 discusses a No Color inspection finding that corrective actions for some Maintenance Rule issues have not been timely and effectively implemented.

4OA3 Event Followup

.1 Unit 2 Charging System Leak and Release

a. Inspection Scope

The inspectors evaluated plant status and mitigating actions for a Unit 2 charging system valve (FCV-122) packing leak and subsequent gaseous release that occurred on May 26. The inspector reviewed the following: plant status operator logs; release calculations; radiation monitor chart recorders; CR 2001001291; procedure FNP-2-AOP-1, RCS Leakage, implementation; emergency classification per procedure FNP-0-EIP-9.0, Emergency Actions and Classifications; and, TS compliance. The inspectors also interviewed selected station personnel. The inspector confirmed that the licensee had properly classified the release as not reportable. The inspectors reviewed the licensee's root cause evaluation and corrective actions for the packing leak.

b. Findings

No findings of significance were identified.

.2 Unit 1 Condenser Leak and Loss of Circulating Water Canal Level

a. Inspection Scope

The inspectors evaluated plant status and mitigating actions for a unplanned Unit 1 power reduction to 70% RTP due to a main condenser tube leak on June 2 and a loss of circulating water canal level on June 3. The inspectors reviewed plant status, operator logs, CRs 2001001348 and 2001001349, procedure FNP-2-AOP-25, Abnormal Primary or Secondary Chemistry, TS compliance, and interviewed selected station personnel.

b. Findings

No findings of significance were identified.

4OA5 Other

.1 Institute of Nuclear Power Operations (INPO) Operations Programs Training Accreditation Report Review

a. Inspection Scope

The inspectors reviewed the final INPO training accreditation assessment report of operations programs conducted in January 2001. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to determine if any significant safety issues were identified that required further NRC follow up.

b. Findings

No findings of significance were identified.

.2 Steam Generator Replacement - Outage Activities

a. Inspection Scope

Inspectors conducted a review of the licensee's replacement steam generator (RSG) activities per the applicable design change procedures (DCPs) and reviewed the Foreign Material Exclusion (FME) controls per Construction Procedure CP-10, Housekeeping, and FNP-0-AP-35, General Plant Housekeeping and Cleanliness Control, as well as, FNP-0-AP-44, Cleanliness of Fluid Systems & Associated Components. The inspectors interviewed craft and supervision doing the RSG activities, discussed outstanding Non Conformance Reports (NCRs) and their impact, and reviewed the implementation of FNP-0-ACP-99.0, Steam Generator Replacement Project Verification Plan. The inspectors routinely monitored the implementation of radiological controls. Inspections of plant operating condition changes and temporary services for SGR activities is documented in section 1R20 of this report. The following SGR activities and DCPs were reviewed:

- DCP 97-2-9316, Steam Generator Replacement and Reactor Coolant Work
- DCP 97-2-9322 Bio-wall construction, also reviewed against CP-C-1, Concrete Procedure (WO 20004820)
- FNP-2-ETP-4462, Unit 2 - Power Ascension Following Steam Generator Replacement
- FNP-2-STP-115.1, Reactor Coolant System Flow Measurement (W00645379)
- FNP-2-STP-110, Determination of Limiting Hot Channel Factors FQ(z) and FdeltaHN

b. Findings

No findings of significance were identified.

.3 Steam Generator Replacement - ISI Activities

a. Inspection Scope

The inspectors reviewed the activities listed in Attachment 1 for conformance to the applicable codes and procedures and witnessed selected activities associated with each evolution. The inspectors also reviewed the documentation for the activities listed in Attachment 1 for conformance with applicable codes, standards and procedures. The review included independent evaluation of portions of the documentation, as applicable.

The inspectors discussed SGRP activities and the resolution of licensee identified problems with the licensee's SGRP Verification Team and associated licensee and contractor management and walked down the reinstallation of piping and components and the biowall for steam generator (SG) 'C'. The inspectors also attended selected job preparation briefings and reviewed Design Change Engineering Evaluations (DCR) documents for SGRP activities. The inspectors observed personnel perform reactor coolant pipe preparation and welding and QC personnel examine weld preparation and fit-up. The inspectors reviewed individual qualification records for Nondestructive examination inspectors, QC inspectors, and welders to verify that they were qualified for these activities.

The inspectors observed machining equipment operations and nondestructive examinations during welding preparations on the replacement steam generator nozzles. The inspectors reviewed special procedures for cutting, machining, welding, and nondestructive examination. The welding procedure essential variables were compared to data provided in the ASME required supporting Procedure Qualification Reports (PQRs).

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mike Stinson, Plant General Manager, and other members of licensee management at the conclusion of the inspection on July 6, 2001. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee
R. V. Badham, Administration Manager
C. L. Buck, Technical Manager
R. M. Coleman, Outage and Modification Manager
C. D. Collins, Operations Manager
K. C. Dyar, Security Manager
D. E. Grissette, Assistant General Manager - Plant Support
J. G. Horn, Outage Planning Supervisor
J. R. Johnson, Assistant General Manager - Operations
R. R. Martin, Engineering Support Manager
B. L. Moore, Maintenance Manager
C. D. Nesbitt,, Training Recovery Manager
W. D. Oldfield, Safety Audit Engineering Review Supervisor
L. M. Stinson, Plant General Manager - FNP
R. J. Vanderbye, Emergency Preparedness Coordinator
L. Williams, Training Manager
G. Dykes, Maintenance Rule Coordinator
R. Martin, Engineering Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

NCV 348, 364/2001-02-01, Inadequate Maintenance Rule Scoping

Attachments: As stated

ATTACHMENT 1

List of Documents Reviewed

Section 1R06
FNP-0-AOP 10.0, Loss of Service Water
FNP-0-AOP 9.0, Loss of Component Cooling Water
FNP-0-AOP 7.0, Loss of Turbine Building Service Water
FNP-0-AOP 12.0, RHR System Malfunction
Functional System Description A-181000, Component Cooling Water
Functional System Description A-181000, Service Water System
FNP-1(2)-ARP-1.1 Windows C5, D1, E1, E3
FNP-1(2)-ARP-3.1 Windows A2, B2, G2, H2, F2
FNP-1(2)-ARP-3.2 Windows A2, B2, C2, E2, E3, G2, H2, F2
FNP-0-ARP-10 Windows 3, 4, 11, 13, 14
Drawing D-350800, Aux. Bldg. Conc-Penetration Seals Key Plan @ El. 83'-0" (Unit 1)
Drawing D-356035, Aux. Bldg. Conc-Penetration Seals Key Plan @ El. 83'-0" (Unit 2)

Section 1R08

Altran Corporation Design Review, Farley Unit 2 Main Steam Line Piping Analysis Review
Altran Corporation Technical Report No. 01812-TR-001, Metallurgical Analysis of Bulged Main Steam Piping
Bechtel Welding Procedure (WP) P1-T-0(Cvn+10)R0
Bechtel WP P1-T(ER 70S-6) (Cvn+10)R0
Bechtel WP P3(G3),P1(G2)T-0(Cvn+10)R0
Bechtel WP P3(G3),P1(G2)-T(ER 70S-6)(Cvn+10)R0
Farley Condition Report (CR) 2001000369, U2 MS Line on 155' of Turbine Bldg had vibrations measurements above the OM-3 stress limit.
CR 2001000525, Gouges on MS pipe noted following removal of existing metal reflective insulation.
CR 2001000529, Three bolts found between the lower MSR-1S whip restraint ring and the main steam pipe.
CR 2001000555, ...main steam pipe at the exit of SG “B” at EL 195' 7-1/4" has been in hard contact with whip restraint 2MSR-1W during normal operating conditions.
CR 2001000704, 2A Main Steam Line in CTMT UT exam indicates cracks in the first 18" of the longitudinal weld, beginning at the circumferential weld at the CTMT penetration.
CR 2001000759, As documented in Bechtel NCRs U2-038, 040, and 044, there are small areas at the RCS pipe (elbow) to SG nozzle welds where the as-found wall thickness was less than the minimum specified in the original Westinghouse piping specification.
DCR No. 97-2-9316, SGR - Replace Steam Generators and Reactor Coolant System Work
DCR No. S01-2-9721, Installation of Vibration Dampers on Unit 2 Main Steam Piping in the Containment Building
DCR No. 97-2-9318, SGR - Large Bore Secondary Systems Piping Modifications
DCR No. B01-2-9711, Repair of Main Steam Hangers in Containment and Main Steam Valve Room
DCR No. S01-2-9716, Installation of Vibration Dampers on Unit 2 Main Steam Piping in the Turbine Building
Enidine, Inc.Installation, Operation and Maintenance Manual for WEAR™ Restraint ENIDINE Part No. WR10734 - Farley Nuclear Plant Purchase Order No. FN011250

Farley Root Cause Summary Problems with the Unit 2 Main Steam System Piping and Supports.
REA 01-2440-03, Post U2R14 Collection and Analysis of Main Steam Data
SGRP Verification Team Summary Reports, Weekly reports from January 11, 2001 through April 1, 2001
TE-BS-01-2440-001, Stress Analysis of Main Steam Line From Steam Generator 2A Inside Containment (Prob. 501) - Interim Operability Assessment.
TE-BS-01-2440-002, Stress Analysis of Main Steam Line From Steam Generator 2B Inside Containment (Prob. 502) - Interim Operability Assessment.
TE-BS-01-2440-003, Stress Analysis of Main Steam Line From Steam Generator 2C Inside Containment (Prob. 503) - Interim Operability Assessment.

Section 4OA5.3

Welding of Reactor Coolant Piping (RCP) to the replacement steam generators (RSGs)
Fit-up and welding of main steam (MS) and feedwater (FW) piping to the RSGs.
Nondestructive examination (NDE) of selected RCP, MS, and FW piping welds.
Welding procedure qualifications, welder qualifications, and welding filler material certifications for: RCS “A” Hot leg weld FW-1-SG; RCS “B” Cold leg weld FW-2-SG; MS “B” FW-5-SG R1; MS “C” FW-1-SG; FW “A” FW-26-SG; and FW “B” FW-13-SG R2
Final acceptance radiographs for the welds listed above.
Measurement of cold and hot settings for replacement piping and pipe supports.