UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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April 22, 2004

Southern Nuclear Operating Company, Inc.
ATTN: Mr. L. M. Stinson
Vice President
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2004002 AND 05000364/2004002

Dear Mr. Stinson:

On March 27, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Joseph M. Farley Nuclear Plant, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 1, 2004, with Mr. Don Grissette and other members of your staff.

The 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.

This report documents two NRC-identified findings of very low safety significance (Green), which were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these two violations as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Farley Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the

NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Brian R. Bonser, Chief
Reactor Projects Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000348/2004002 and 05000364/2004002
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-348, 50-364
License Nos.:	NPF-2, NPF-8
Report Nos.:	05000348/2004002 and 05000364/2004002
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	Joseph M. Farley Nuclear Plant
Location:	7388 N. State Highway 95 Columbia, AL 36319
Dates:	December 28, 2003 to March 27, 2004
Inspectors:	C. Patterson, Senior Resident Inspector R. Fanner, Resident Inspector B. Crowley, Senior Reactor Inspector (Section 4OA5.1) J. Lenahan, Senior Reactor Inspector (Sections1R08 and 4OA5.5)
Approved by:	Brian R. Bonser, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000348/2004002, 05000364/2004002; 12/28/2003 - 03/27/2004; Joseph M. Farley Nuclear Plant, Units 1 & 2; Maintenance Risk Assessments and Emergent Work Evaluation, Operability Evaluations.

The report covered a three-month period of inspection by resident inspectors and announced inspection by two senior reactor inspectors. Two Green non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July, 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A Green non-cited violation (NCV) was identified for failure to provide an adequate maintenance procedure in accordance with TS 5.4.1.a. Licensee procedure FNP-1-EMP-1341.08, Auxiliary Building Battery Equalization, did not ensure that electrical separation and isolation were maintained when a non-Class 1E single cell battery charger was used to charge a single battery cell on the safety-related 1B battery.

  This finding is more than minor because it adversely impacted the Mitigating Systems cornerstone attribute of equipment performance by potentially challenging the reliability of the 1B battery because procedure FNP-1-EMP-1341.08 did not require electrical separation between Class 1E and non-Class 1E components. This finding was determined to be of very low safety significance because there was no actual fault and other trains of electrical equipment were available.(Section 1R13)

- Green. A Green NRC-identified NCV was identified for failure to meet the ASME Boiler and Pressure Vessel Code requirements of 10 CFR 50.55a section (a)(2) for systems and components of a pressurized water-cooled reactor or seek a proposed alternative as permitted by section (a)(3) for three through-wall leaks in ASME Code Class 3 piping of the Service Water (SW) system. The leaks, when identified, were not repaired to ASME code requirements or a proper evaluation performed for an alternative non-code repair as discussed in Generic Letter (GL) 90-05, Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1,2, and 3 Piping.

  This finding is more than minor because it adversely affected the equipment performance attribute of the mitigating system cornerstone because it had the potential to affect the reliability of the SW system. This finding was determined to be of very low safety significance because there was not a large leak or loss of SW system safety function. (Section 1R15)

B. Licensee Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near 100 percent Rated Thermal Power (RTP) until March 1, when a reactor trip occurred due to failure of the steam generator feedwater pump speed controller. The unit was returned to 100 percent RTP on March 2.

Unit 2 operated at or near 100 percent RTP until February 23 when a power coastdown began. The unit was shut down March 13 to begin a refueling outage.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed three partial system walk-downs to verify the systems listed below were properly aligned when redundant systems or trains were out of service. The walk-downs were performed using the criteria in licensee procedures FNP-0-AP-16, Conduct of Operations - Operations Group, and FNP-0-SOP-0, General Instructions to Operations Personnel. The walk-downs included reviewing the Updated Final Safety Analysis Report (UFSAR), plant procedures and drawings, and checks of control room and plant valves, switches, components, electrical power line-ups, support equipment, and instrumentation.

- Unit 2 Service Water (SW) system during 2B SW pump replacement
- Emergency Diesel Generators (EDGs) 1-2A, 1C, 2C, and 2B during 1B EDG outage
- The 1B Motor-Driven Auxiliary Feedwater (MDAFW) and 1 Turbine Driven Auxiliary Feedwater (TDAFW) pumps during 1A MDAFW Inservice Test

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted a walk-down of the 10 fire areas listed below to verify 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. To verify implementation, the inspectors also checked that compensatory measures, including fire watches, were in place for degraded fire barriers. The requirements were described in licensee procedures FNP-0-AP-36, Fire Surveillance and Inspection; FNP-0-AP-38, Use of Open Flame; FNP-0-AP-39, Fire Patrols and

Watches; and the associated Fire Zone Data sheets. In addition, the inspectors reviewed procedure change FNP-0-ACP 35.2, that established interim compensatory measures to limit transient combustible materials in areas having large penetration seals with less than a three-hour rating.

• Unit 1 Motor-Driven and Turbine-Driven Pump Rooms, Fire Zone 6
• Unit 1 Hot Shutdown Panel, Fire Zone 12
• Unit 1 1B Battery Room, Fire Zone 16
• Unit 1 1A Battery Room, Fire Zone 17
• Unit 1 1B DC Switchgear Room, Fire Zone 19
• Unit 1 1A DC Switchgear Room, Fire Zone 18
• Unit 1 EDG Building Tunnel A, Fire Zone 75
• Unit 1 EDG Building Tunnel B, Fire Zone 76
• Unit 2 EDG Building Tunnel A, Fire Zone 75
• Unit 2 EDG Building Tunnel B, Fire Zone 76

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

a. Inspection Scope

Inservice Inspection. The inspectors reviewed ISI procedures, observed in-process ISI work activities, and reviewed selected ISI records. The observations and records were compared to the Risk-Informed Inservice Inspection Program approved by NRC in a Safety Evaluation Report dated March 9, 2004, and the ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, No Addenda, to verify compliance. Portions of the following Unit 2 ISI examinations were observed:

Ultrasonic Examination (UT)

- Weld No. APR2-4104-32 on the 6 inch diameter safety injection piping into the hot leg of Loop 1.
- Weld No. APR2-4103-33 on the 6 inch diameter safety injection piping into the cold leg of Loop 1.
- Weld No. APR2-4101-5 on the main steam line

Non-destructive examination (NDE) procedures for the ISI examination activities were reviewed. The inspectors also reviewed NDE reports for visual (VT-3) inspection of 15 pipe supports performed during the current outage. Qualification and certification records for examiners, and equipment for selected examination activities were reviewed. In addition, the inspectors examined snubbers, spring cans, and pipe supports during a walkdown of the Unit 2 containment. Examination of the snubbers included attachment to supporting structures and piping, fluid levels in reservoirs, absence of fluid leakage from the snubbers, and overall condition of the snubbers.

The inspectors reviewed records for the following indications from refueling outage 15 which had been evaluated and accepted for continued service:

- Indication Evaluation Report (IER) 001, Visual Indication on RPV Washer # 30
- IER 002, Damage to Spring Can
- IER 017, Evidence of Leakage on RCP Seals

The inspectors also reviewed records for repairs/replacement of snubber numbers 55-12648, 55-12677 and SS-12684 during refueling outage 15.

IWE Containment Vessel Inspection. The inspectors reviewed the licensee's ISI procedures for the containment inspection to determine if the procedures complied with the Technical Specifications (TS), ASME Boiler and Pressure Vessel Code, Article IWE of Section XI, 1992 Edition and 1992 Addenda, and 10 CFR 50.55a. The inspectors also reviewed records documenting visual inspections performed on the containment building in March 2001 to determine if the licensee program for inspection of the containment was being performed in accordance with the requirements specified in Article IWE of Section XI, 1992 Edition and 1992 Addenda, and 10 CFR 50.55a. The inspectors examined the interior surfaces of the containment liner and the moisture barrier at the intersection of the liner and interior concrete floor area. The inspectors also examined the Unit 2 containment tendon gallery.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed portions of the licensed operator training and testing program to verify implementation of procedures FNP-0-AP-45, Farley Nuclear Plant Training Program; FNP-0-TCP-17.6, Simulator Training Evaluation Documentation; and FNP-0-TCP-17.3, Licensed Operator Continuing Training Program. The inspectors observed scenarios conducted in the licensee's simulator for a failed flow controller, steam generator tube leakage, steam generator tube rupture, and a failed pressure indicator. The inspectors observed high risk operator actions, overall performance, self-critiques, training feedback, and management oversight to verify operator performance was evaluated against the performance standards of the licensee's scenario. In addition, the inspectors observed implementation of the applicable emergency operating procedures listed in the attachment to verify that licensee expectations in procedures FNP-0-AP-16 and FNP-0-TCP-17.6 were met.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the following two issues to verify implementation of licensee procedures FNP-0-M-87, Maintenance Rule Scoping Manual; FNP-0-SYP-19, Maintenance Rule Performance Criteria; and FNP-0-M-89, FNP Maintenance Rule Site Implementation Manual; and compliance with 10 CFR 50.65. The inspectors assessed the licensee's evaluation of appropriate work practices, common cause failures, functional failures, maintenance preventable functional failures, repetitive failures, availability and reliability monitoring, trending and condition monitoring, and system specialist involvement. The inspectors also reviewed condition reports (CRs), interviewed maintenance personnel, system specialists, the maintenance rule coordinator, and operations personnel to assess their knowledge of the program.

- CR 2003003511, U2 Penetration Room Filtration System Train B, exceeded its unavailability
- CR 2004000486, 1C EDG failed to start after 24 month scheduled outage due to a failed air start solenoid

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors assessed the licensee's planning and control for the following seven planned licensee activities to verify the requirements in licensee procedures FNP-0-ACP-52.1, Guidelines for Scheduling of On-Line Maintenance; FNP-0-AP-52, Equipment Status Control and Maintenance Authorization; and FNP-0-AP-16, Conduct of Operations - Operations Group; and the MR risk assessment guidance in 10 CFR 50.65 a(4) were met.

- 1A Hot Shutdown Panel primary power supply voltage low
- 1B 125 volt direct current (VDC) batteries and single cell charger
- 1C EDG - 24 month scheduled outage
- 1A Centrifugal Charging Pump (CCP) - discharge pressure indicator replacement
- TDAFW pump high vibrations
- Containment Cooler Drain valve operation
- SW valve (Q1P16V721B) seal water strainer isolation freeze seal

b. Findings

Introduction. A Green NCV was identified for failure to provide an adequate maintenance procedure in accordance with TS 5.4.1.a. Licensee procedure FNP-1-EMP-1341.08, Auxiliary Building Battery Equalization, did not ensure that electrical separation and isolation were maintained when a non-Class 1E single cell battery charger was used to charge a single battery cell on the safety-related 1B battery.

Description. On February 5, 2004, the resident inspectors identified a non-class 1E battery charger connected to a single cell on the 1B battery. The continuous single cell charge was used to address sulfation of the cell. This single-cell charge was performed using procedure FNP-1-EMP-1341.08.

The residents reviewed the UFSAR, industry specifications, and operating experience to determine the technical basis of using the non-Class 1E battery charger. UFSAR Section 8.3.2, DC Power Systems, stated that all components are designed to conform to class 1E power system design criteria of IEEE Standard 308. IEEE Standard 308 stated that non-Class 1E circuits shall be independent and shall have proper isolation from Class 1E systems and components. This isolation could have been provided and ensured by utilizing Class 1E fuses or breakers. Without isolation capability, an electrical fault of the non-Class 1E battery charger could have been transferred into the 1B battery. After the inspectors discussed this issue with the licensee, the battery charger was removed and CR 2004000795 initiated to address this issue.

Analysis. This finding is more than minor because it adversely impacted the Mitigating Systems cornerstone attribute of equipment performance by potentially challenging the reliability of the 1B battery because procedure FNP-1-EMP-1341.08 did not require electrical separation between Class 1E and non-Class 1E components. This finding was determined to be of very low safety significance because there was no actual fault and other trains of electrical equipment were available.

Enforcement. TS 5.4.1.a requires written procedures be established, implemented, and maintained covering the activities recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A. RG 1.33, Appendix A, Item 9 a. stated, in part, that maintenance that can affect the performance of safety-related equipment should be performed in accordance with written procedures appropriate to the circumstances. Contrary to the above, procedure FNP-1-EMP-1341.08, Auxiliary Building Battery Equalization, was not appropriate to the circumstances in that electrical isolation between the non Class 1E single cell battery charger and the 1B battery was not required or established. The non-Class 1E charger was in use periodically from September 17, 2003 to February 27, 2004. Because this failure to maintain adequate written procedures is of very low safety significance and has been entered in the licensee's corrective action program (CR 2004000795), this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000348/2004002-01, Inadequate Procedure for Electrical Separation of Single Cell Battery Charger and Safety-related Battery.

1R14 Personnel Performance During Non-Routine Plant Evolutions

a. Inspection Scope

For the non-routine events described below, the inspectors assessed the licensee's use of operating procedures, surveillance test procedures, annunciator procedures, abnormal and emergency operating procedures listed in the attachment, control room actions, command and control, post event recovery, management involvement, training expectations, previous CRs, maintenance work history, and communication. The inspectors reviewed operator logs, plant computer data, control room strip charts, post event/trip report, and discussed actions with operations personnel.

- Unit 1 reactor trip due to High-High steam generator level caused by a failed feedwater pump speed controller card
- Unit 2 power coastdown (Tavg) prior to refueling outage.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six operability evaluations to verify they met the requirements of licensee procedures FNP-0-AP-16, and FNP-0-ACP-9.2, Operability Determination (OD), for technical adequacy, consideration of degraded conditions, and identification of compensatory measures. The inspectors reviewed the evaluations against the design bases, as stated in the UFSAR and Functional System Descriptions (FSD), to verify system operability was not affected.

- CR 2004000271, 1B EDG Oil Leak
- CR 2003002999, 1B MDAFW pump service water leak
- CR 2004000407, 2A Component Cooling Water (CCW) Heat exchanger tube plugging
- CR 2004000795, 1B 125 VDC batteries with external charger attached to a cell
- CR 2004000037, Motor Control Center IV Control Power Transformer Operability
- CR 2004001030, MDAFW oil impurities

b. Findings

Introduction. A Green NRC-identified NCV was identified for failure to meet the ASME Boiler and Pressure Vessel Code requirements of 10 CFR 50.55a section (a)(2) for systems and components of a pressurized water-cooled reactor or seek a proposed alternative as permitted by section (a)(3) for three through-wall leaks in ASME Code Class 3 piping of the SW system. The leaks, when identified, were not repaired to ASME code requirements or a proper evaluation performed for an alternative non-code repair as discussed in Generic Letter (GL) 90-05, Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1,2, and 3 Piping.

Description. On November 1, 2003, the licensee wrote CR 2003002999 to document a pin-hole leak on the SW supply to the 1B MDAFW pump. Section XI of the ASME code required a code-approved repair of flaws regardless of the plant's operational mode. However, GL 90-05 allowed licensees to perform a temporary non-code repair of through-wall flaws that would otherwise require a plant shutdown. The licensee performed an evaluation of the leak and concluded there was no immediate structural threat. The leak would be monitored until the next refueling outage when repairs could be performed. The inspectors questioned this approach since neither a code repair nor a non-code repair was being performed. The licensee wrote CR 2003003034 and Request for Engineering Review (RER) 03-375 to resolve the issue.

On December 12, 2003, the licensee concluded that the 1B MDAFW pump SW leak as well as two other SW leaks required temporary non-code repairs per the guidance of GL 90-05. One of the additional leaks, a through-wall on the 1C SW pump mini-flow valve, was identified June 23, 2003, and documented in CR 2003001436. This leak was repaired in January 2004. The other additional leak, a through-wall leak in a 20 inch SW supply line to the circulating water canal, was identified November 16, 2002, and documented in CR 2002002791. The licensee submitted the non-code repairs for NRC approval and developed a schedule for completing flaw characterization and augmented examinations by January 16, 2004.

Analysis. This finding is more than minor because it adversely affected the equipment performance attribute of the mitigating system cornerstone because it had the potential to affect the reliability of the SW system. This finding was determined to be of very low safety significance because there was not a large leak or loss of SW system safety function.

Enforcement. 10 CFR 50.55a section (a)(2) states, in part, that systems and components of pressurized water-cooled reactors must meet the requirements of the ASME Boiler and Pressure Vessel Code or licensees must seek a proposed alternative from the Director of Nuclear Reactor Regulation as permitted by section (a)(3). Contrary to the above, the licensee failed to meet this requirement for three through-wall leaks of ASME Code Class 3 piping. This condition existed upon discovery of each leak until one leak was repaired and evaluations conducted for the other two leaks per GL90-05 and code relief requested from the Office of Nuclear Reactor Regulation. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program (CR 2003003034), this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000348,364/2004002-02, Failure to Perform Required Repairs of Service Water System ASME Class 3 Piping.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the criteria contained in licensee procedures FNP-0-ACP-52.1, Guidelines for Scheduling of On-Line Maintenance; FNP-0-PMT-0.0, Post Maintenance Test Program; and procedures listed in the attachment to verify post-maintenance test procedures and test activities for the following five systems/components were adequate to verify system operability and functional capability:

- 2B SW pump following pump replacement
- 1B EDG testing after scheduled six month outage
- 1A CCW pump run following breaker maintenance
- 1C EDG testing after scheduled 24 month outage
- 1B CCP pump after replacement of power supply breaker DK-07

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 Spring 2004 2R16 refueling outage for conformance to licensee procedures FNP-0-UOP-4.0, General Outage Operations Guideline, and FNP-1-UOP-4.1, Refueling Outage Operation. Surveillance tests were reviewed to verify results were within the TS required specification. Shut down risk, management oversight, procedural compliance, and operator awareness were evaluated for each of the following activities. Associated licensee procedures are listed in the Attachment.

- Refueling outage risk plans and safety oversight
- Decay heat removal and spent fuel pool cooling (SFP) system operations
- Core refueling operations
- Reactor vessel disassembly and assembly activities
- Outage-related surveillance tests
- Reactor coolant drain down activities and mid-loop operations
- Mode changes, cool down limits, and TS compliance
- Outage control center oversight and operations outage conduct
- Electrical system alignments and availability
- Problem identification and resolution activities
- Clearance activities

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed surveillance test procedures and either witnessed the test or reviewed test records for the following six surveillance tests to determine if the test adequately demonstrated equipment operability and met the TS requirements. The inspectors reviewed the activities to assess for preconditioning of equipment, procedure adherence, and valve alignment following completion of the surveillance. The inspectors reviewed licensee procedures FNP-0-AP-24, Test Control; FNP-0-M-050, Master List of Surveillance Requirements; and FNP-0-AP-16, and attended selected briefings to determine if procedure requirements were met.

- FNP-1-STP-80.1, DG 1B Operability Test
- FNP-2-STP-33.0, Solid State Protection System Train A Operability Test
- FNP-2-STP-9.0, Reactor Coolant System Leakage Test
- FNP-2-STP-22.1, 2A Auxiliary Feedwater Pump Quarterly Inservice Test
- FNP-2-STP-24.1, 2B Service Water Pump Quarterly Inservice Test
- FNP-2-STP-608.0, Main Steam Safety Valve Operational Test

b. Findings

No findings of significance were identified

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following two minor departures (MD), and associated 10 CFR 50.59 screening criteria against the system design bases information and documentation and the licensee's temporary modifications procedure FNP-0-AP-8, Design Modification Control. The inspectors reviewed implementation, configuration control, post-installation test activities, drawing and procedure updates, and operator awareness for this temporary modification.

- MD 02-02724, Temporary Leak Abatement Using a Soft Patch on Q2P16V0560 (SW to CW Canal)
- MD 03-02747, 1C Diesel Generator Repair and Speed Signal Generator Annunciator

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee submittals for the performance indicators (PIs) listed below to verify the accuracy of the data reported. The PI definitions and the guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Rev. 2, and licensee procedure FNP-0-AP-54, Preparation and Review of NRC Performance Indicator Data, were used to verify procedure and reporting requirements were met.

Mitigating Systems Cornerstone
- Unplanned Scrams
- Scrams with Loss of Normal Heat Removal
- Unplanned Power Changes

The inspectors reviewed samples of raw PI data, Licensee Event Reports (LERs), and Monthly Operating Reports for the period covering January 2003 through December 2003. The data reviewed from the LERs and Monthly Operating Reports was compared to graphical representations from the most recent PI report. The inspectors also examined a sampling of operations’ logs and procedures to verify the PI data was appropriately captured for inclusion into the PI report as well as insuring that the individual PIs were calculated correctly. For Unit 2 the second, third, and fourth quarters of the Scrams with Loss of Normal Heat Removal, the value shown graphically was 0.1 which was incorrect. The actual value was zero. This error did not represent a negative change in the PI and was addressed by CR 2004001276.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

a. Inspection Scope

Daily Condition Report Reviews. As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee’s corrective action program. This review was accomplished by reviewing hard copies of each condition report, attending daily screening meetings, and accessing the licensee’s computerized database.

Annual Sample Review. The inspectors reviewed the completed action for CR 2004000139 (post maintenance test data on January 8, 2004, following replacement of the 2B SW pump). This CR was written based on the SW pump being declared operable without a proper evaluation of the flow data. The inspectors reviewed the CR to verify that corrective actions taken would prevent declaring a pump operable without a comparison to a reference or standard value and prevent marking the reference value in the procedure as “Not Applicable” when data was taken to establish a baseline. The pump had developed sufficient flow to be declared operable but was not reflected in the post maintenance test procedure.

b. Findings and Observations

No findings of significance were identified. The inspectors concluded that the initial corrective action did not ensure resolution of the issue. The single assigned action item for the CR was to have the engineering department review the new pump flow data prior to declaring the pump operable. However, from discussion with the licensee, the review was already routinely performed. The difference in this case was that the engineer was not aware of when the pump was being declared operable. The inspectors concluded the CR did not correct the problem identified because there were no corrective actions to address the post maintenance test or how the reference value in the procedure could be marked as “Not Applicable” without a procedure change occurring. Also, the licensee did not look at the extent of condition to see if the problem existed in other cases. Additional discussions were conducted with the licensee and CR 2004001167 was written with corrective action items assigned to address these concerns.

4OA3 Event Followup

a. Inspection Scope

On March 1, Unit 1 automatically tripped from 100 percent power due to a failure of the steam generator feedwater pump speed controller. Steam generator (SG) water levels increased causing the reactor trip on high SG water level. The inspectors responded to the event to verify that plant conditions were stable and all safety systems had responded as expected. The licensee initiated CR 2004000824 to address corrective action for the trip. This issue will receive further review with closure of the Licensee Event Report (LER).

b. Findings

No findings of significance were identified.

4OA5 Other Activities

1. (Closed) Temporary Instruction (TI) 2515/150, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009)

a. Inspection Scope

The inspectors observed activities relative to inspection of the reactor vessel head (RVH) and RVH penetration nozzles in response to NRC Bulletins 2001-01, 2002-01, 2002-02 and NRC Order EA-03-009 Modifying Licenses dated February 20, 2004. The inspection included review of NDE procedures, assessment of NDE personnel training and qualification, and observation and assessment of visual (VT), UT, and eddy current (ET) examinations. Discussions were also held with contractor representatives and other licensee personnel. The activities were examined to verify licensee compliance with regulatory requirements and gather information to help the NRC staff identify possible further regulatory positions and generic communications. Specifically, the inspectors reviewed or observed the following:

1) Bare Metal VT Examination

- observed a portion of in-process bare metal remote video VT inspection of RVH Nozzle Nos. 19, 25, 35, 43, 44, and 61 (including surfaces around the nozzles)
- reviewed RVH bare metal VT video Inspection Tape 1 (a total of 3 Inspection Tapes covered inspection of all of the RVH nozzles) - specifically inspected portions of RVH Nozzles 1, 2, 3, 8, 13, 16, 19, 20, 25, 27, 29, 34, 36, 37, 39, 40, 42, 43, 49, 54, 55, 57, 58, 60, 61, 67, 68 and 69 (including surrounding head surfaces)
- reviewed RVH bare metal VT video Continuous Tape 10
- reviewed RVH bare metal “still pictures” for RVH Nozzles 19, 20, 24, 28, 32, 42, 51, 62, and 68

The inspections were conducted in order to verify absence of boron crystals indicative of a leak and to verify the integrity of the RVH.

2) UT and ET Examination of RVH Nozzles

- observed a portion of in-process UT and ET scanning of RVH Nozzle Nos. 28, 47, 48, and 52
- reviewed the UT and ET data and results for RVH Nozzle Nos. 16, 24, 27, 28, 36, 47, 52 and 64

- reviewed ET data for RVH vent nozzle

UT observations/reviews included review of results intended to assess for leakage into the interference fit zone of the nozzles.

3) The inspectors discussed with licensee personnel the susceptibility ranking calculation and reviewed the results of the calculation. The basis for head temperature input was reviewed to verify appropriate plant specific information was used in the time-at-temperature model for determining RVH susceptibility ranking.

4) The inspectors reviewed licensee procedures and inspection results for visual examinations to identify potential boric acid leaks from pressure-retaining components above the RVH.

b. Findings and Observations

1) Verification that the examinations were performed by qualified and knowledgeable personnel.

The inspectors found that visual and NDE inspections were being performed in accordance with approved and demonstrated procedures with trained and qualified inspection personnel. All examiners had significant experience, including experience inspecting RVHs. In addition to qualification to Code requirements, VT, UT and ET personnel had additional training on RVH inspections.

2) Verification that the examinations were performed in accordance with approved and demonstrated procedures.

The Farley Unit 2 RV head has 56 full length nozzles, five partial length nozzles, 4 instrument nozzles, four spare nozzles, and one vent nozzle or a total of 70 nozzles. The bare head remote visual inspection was performed in accordance with Westinghouse Procedure MRS-SSP-1447. The procedure used crawler mounted cameras which scanned one quadrant at a time for each of the 70 nozzles. The entire bare metal surface was covered with these scans.

All nozzles, except the vent nozzle, received remote mechanized UT and ET examination from the inside surface in accordance with Westinghouse approved procedures WDI-ET-004, WDI-ET-008, WDI-UT-010, and WDI-UT-013. Sixty-one of the 69 large-bore nozzles had thermal sleeves and required the use of a blade probe. The blade probe employed: a set of “time of flight” (TOFD), 44 degree, 6 MHZ, Longitudinal (L) Wave UT transducers directed in the axial direction; a 0 degree, 2.25 MHz L Wave UT transducer; and a +point ET coil. Scanning was in the axial direction. The remaining 8 large bore nozzles were inspected with an open-bore tool employing: two sets of TOFD 55 degree, 5 MHz, L wave transducers (one set directed circumferentially and the other directed axially); a 0 degree, 2.25 MHz, L Wave UT transducer; and a +point ET coil. The inspection area for the 69 large-bore nozzles extended from a minimum of 2" above the J-groove weld to the bottom of the nozzle.

The vent nozzle was ET inspected using Westinghouse approved procedures WDI-STD-101 and WDI-STD-114. The inside diameter from the bottom of the nozzle to above the outside of the RVH surface was inspected using 2 ‘bobbin’ coils and an array of ‘+point’ coils. The vent line J-groove weld surface was inspected using an array of ‘+point’ coils.

The inspectors reviewed the Westinghouse procedures and observed in-process examinations as noted above. Approved acceptance criteria and/or critical parameters for RVH leakage were applied in accordance with the procedures.

As reflected in the Safety Evaluation Report for Farley, dated April 25, 2003, and as required by the February 20, 2004 revision of NRC Order EA-03-009, the licensee expected to perform NDE to at least 1" below the bottom of the J-groove welds for the 69 large-bore nozzles. However, due to a physical limitation (distance from the bottom of the J-groove weld to the shoulder of the machined area of the nozzle was slightly less than 1"), the 1" minimum could not be met for 5 of the 69 nozzles. For the 5 nozzles (Nozzles 62, 63, 65, 66 and 69), the distance inspected on the downhill side of the weld varied from 0.76" to 0.96". This limitation was documented in Licensee Relaxation Request Letter NL-04-0494 dated March 25, 2004, as supplemented by Letter NL-04-0537 dated April 1, 2004.

The NDE techniques and procedures being used had been previously demonstrated under the MRP Inspection Demonstration Program.

3) Verification that the licensee was able to identify, disposition, and resolve deficiencies.

   All indications of cracks, leakage or head wastage were required to be reported for further inspection and disposition. Based on observation of the inspection process, the inspectors considered deficiencies would be appropriately identified, dispositioned and resolved. No cracks, leakage or wastage were identified.

4) Verification that the licensee was capable of identifying the primary water stress corrosion cracking (PWSCC) and/or head corrosion phenomenon described in NRC Order EA-03-009.

   The licensee performed NDE examinations and bare metal visual inspection of all of the RVH nozzles and the RVH surfaces during the outage. As noted above, the NDE techniques had been previously demonstrated under the MRP Inspection Demonstration Program as capable of detecting PWSCC type manufactured cracks as well as cracks from actual samples from another site. Based on the demonstration, observation of in-process inspections, and review of inspection data for NDE and bare metal visual inspections, the inspectors concluded the licensee was capable of identifying cracking and/or corrosion as described in the NRC Order.

5) Evaluate condition of the reactor vessel head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions).

   Although minor debris was observed, the inspectors noted that it was loose, was not associated with nozzle leakage, and was easily removed allowing visual inspection of 100 percent of each of the 70 RVH nozzles and head surfaces during the remote visual inspection of the head. There were no obstructions to preclude inspection of the bare metal surface in accordance with the Order.

6) Evaluate ability for small boron deposits, as described in NRC Bulletin 2001-01, to be identified and characterized.

   The inspectors observed that the resolution of the video camera provided capability of detecting any debris or small boron deposits on the bare metal head. There were no obstructions to preclude a 100 percent visual inspection of the RVH penetrations. As noted above only loose debris was noted at the head to penetration area, but was easily removed. In addition to the video, a series of good resolution digital still pictures were taken of each nozzle to head area.

7) Determine extent of material deficiencies (associated with the concerns identified in the Order and Bulletins) which were identified that required repair.

   No examples of RVH leakage or material deficiencies were identified during the visual or NDE examinations.

8) Determine any significant items that could impede effective examinations.

   As noted above 61 nozzles had thermal sleeves requiring the use of blade probe UT and ET inspections. However, centering tabs/rings were well above the inspection area and the required inspections could be performed. No significant items to impede the examination process were noted during observation of the visual or NDE examinations.

9) Determine the basis for the temperatures used in the susceptibility calculation.

   The inspectors reviewed the Farley Unit 2 susceptibility calculation and the basis for the RVH temperatures used in the calculation. Based on review of the calculation results and discussions with licensee personnel, the temperatures used for the Farley Units 1 and 2 susceptibility calculations were based on measured temperatures from four thermocouples (heated junction thermocouples installed inside the RV head), recorded and averaged monthly in accordance with Surveillance Test Procedure FNP-2-STP-108, and an analysis for the Farley Units documented in Westinghouse WCAP 15925 (September 2002). A head temperature of 596.9 degrees F was used for Unit 2 in response to NRC Generic Letter 97-01 and has been used for subsequent susceptibility calculations. This was rounded up to 597 degrees F for both Units when reported in response to NRC Bulletin 2002-01.

The inspectors reviewed the monthly surveillance results for the last Unit 2 operating cycle and found that the temperature averages ranged from 599.5 degrees F early in the cycle to 595.25 degrees late in the cycle. The 596.9 or 597 degrees F is probably near the average for the operating cycle. Based on the lower temperature (592.7 degrees F) presented in the Westinghouse WCAP, the temperatures used for the susceptibility calculation appear to be conservative. However, regardless of the temperature used for the susceptibility calculation, both Farley Units have been determined to be in the high susceptibility category and have been inspected to high susceptibility requirements since issue of the first NRC Bulletin.

10) Determine if the methods used for disposition of NDE identified flaws were consistent with NRC flaw evaluation guidance.

No flaws were identified.

11) Determine if procedures existed to identify potential boric acid leaks from pressure-retaining components above the RVH and if the licensee performed proper followup for indications of boric acid leaks.

The licensee requirements to inspect components above the RVH each refueling outage for evidence of leakage, including boron deposits, are detailed in three procedures, Engineering Technical Procedure FNP-0-ETP-4494, Operating Procedure FNP-2-UOP-2.2, and Maintenance Procedure FNP-2-MP-1.0. The inspections are performed, documented and dispositioned by procedure FNP-2-UOP-2.2 and FNP-2-MP-1.0. The inspectors reviewed the completed copies of these two procedures for the current Unit 2 outage. The licensee did not identify any evidence of current leakage.

2. (Closed) TI 2515/152, Rev.1, Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02) (Unit 2)

a. Inspection Scope

The inspectors reviewed the licensee’s inspection activities related to the Unit 2 reactor vessel lower head penetrations in response to NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity, in accordance with NRC TI 2515/152, Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02), dated November 5, 2003. The inspection included review of Visual Test (VT) procedures, assessment of VT personnel training and qualifications, and observation and assessment of VT examinations. Specifically, the inspectors visually inspected the lower penetration nozzles and observed in-process bare metal video VT inspection. The inspectors reviewed the complete video inspection.

b. Findings and Observations

The inspectors found that the VT examinations were performed by trained and ASME VT-2 Level III qualified inspection personnel. The examiners were experienced and had additional training in inspecting the lower head penetrations. The inspectors verified the adequacy of procedure FNP-0-NDE-100.47, Visual Examination of Reactor Vessel Bottom Mounted Instrumentation Penetrations, used to conduct the examination.

The licensee performed VT examinations of all 50 nozzle penetrations and the lower head. The VT-2 inspection included inspection of the circumference of each nozzle and was capable of identifying any pressure boundary leakage as described in the bulletin and any lower head corrosion. There were no impediments identified that would impact VT examination.

The inspectors observed the visual clarity, resolution, and color of the video inspection process allowed for effective visual examination of the vessel lower head surface and circumferential coverage of each head penetration. The visual inspection was capable of identifying small debris or boric acid deposits as a result of primary water stress-corrosion cracking through evidence of leakage from a penetration. No leakage was identified from any of the vessel lower head penetrations.

The examination involved a camcorder and video taping of the lower reactor vessel head surface in the area of the 50 nozzles as well as the circumference of each nozzle. The inspection was conducted using a camcorder manually positioned around the bottom head area. The inspectors observed the condition of the bottom head area and a portion of the video taping.

There were no examples of leakage sources, insulation, debris, dirt, or other physical impediments that prevented a complete visual examination. The vessel lower head was free of debris, dirt, or large boron deposits. There was no evidence of any leakage or stains of any kind in the bottom head area. The head was clean and no chemical analysis of any material was required.

3. (Discussed) TI 2515/153, Reactor Containment Sump Blockage (NRC Bulletin 2003-01)

a. Inspection Scope

The inspectors reviewed the licensee's activities in response to NRC Bulletin 2003-01, Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors, dated June 9, 2003. The inspection included review of the licensee's 60 day Bulletin response letter dated August 7, 2003, review of interim compensatory measures implemented to reduce the potential risk due to post-accident debris blockage on emergency sump recirculation, and walk-down of the Unit 2 containment prior to re-start from the current refueling outage to identify if any sources of potential debris existed that could impact the containment recirculation sump performance. The inspectors reviewed the following compensatory actions identified in the licensee's

August 7, 2003, response to verify the actions were either implemented or planned and scheduled.

b. Findings and Observations

1) Operator training on indications of and response to sump clogging:

The inspectors reviewed Training Advisory Notice (TAN) 20030714A, FNP Response to NRC Bulletin 2003-01, Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors. The Emergency Core Cooling System (ECCS) logs were revised to annotate specific Residual Heat Removal (RHR)/Low Head Safety Injection (LHSI), Charging/High Head Safety Injection (HHSI), and Containment Spray System (CSS) parameters to monitor for signs of sump clogging. Possible indications of sump clogging would be oscillations or unexplained reductions in system flows, pump amperes or discharge pressure. This training advisory was issued to licensed personnel.

2) Procedural modifications, if appropriate, delaying the switchover to containment sump recirculation:

The licensee determined the existing procedural guidance in ECA-1.1, Loss of Emergency Coolant Recirculation, provided adequate guidance for a complete loss of Safety Injection or CSS recirculation flow path. However, the licensee planned to review any future Westinghouse Owners Group recommendations when issued and determine if any specific changes are required.

The procedure provides guidance to reduce ECCS and CSS flows to conserve Refueling Water Storage Tank (RWST) inventory while efforts to restore normal ECCS flow paths are undertaken.

3) Ensuring that alternate water sources are available to refill the RWST or to otherwise provide inventory to inject into the reactor core and spray into the containment atmosphere:

The licensee determined procedure ECA-1.1, Loss of Emergency Coolant Recirculation, has guidance to add makeup to the RWST and/or consult the Technical Support Center (TSC) staff to determine alternate sources for makeup. Severe Accident Management Guideline, SAG-8, Flood Containment, has details for providing alternate un-borated sources of RWST makeup if needed.

The inspectors reviewed procedure ECA-1.1. Step 5 states makeup to the RWST as necessary in accordance with procedure SOP-2.3, Chemical and Volume Control System Reactor Makeup Control System, or consult the TSC.

4) More aggressive containment cleaning and increased foreign material controls:

The licensee determined existing procedures provided adequate guidance for containment cleaning and foreign material control. The inspectors reviewed the following procedures used during the Unit 2 Spring, 2004 outage:

- FNP-2-STP-34.0, Containment Inspection (General)
- FNP-2-STP-34.2, Containment ECCS Sump Intake Inspection
- FNP-2-STP-34.1, Containment Inspection (Post Maintenance)

In addition, the inspectors performed a walk-down of the Unit 2 containment at the start of the outage to check containment conditions near the sumps. The inspectors inspected the sumps during the licensee's sump inspection. The inspectors conducted a closeout inspection of containment at the end of the outage.

5) Ensuring containment drainage paths are unblocked:

The inspectors reviewed procedure FNP-2-UOP-4.1, Controlling Procedure for Refueling, and verified it contains procedure steps for ensuring the reactor cavity drain valves are open and blind flanges removed. In addition, the inspectors verified the procedure was implemented during the refueling outage.

6) Ensuring sump screens are free of adverse gaps and breaches:

The inspectors reviewed procedure FNP-2-STP-34.2, Containment ECCS Sump Intake Inspection,(and there are steps) to ensure that sump screens are not restricted by debris, are properly installed, the wire mesh is not damaged, and gaps greater than 1/8 of an inch are not present in the mesh.

4. <u>(Discussed) TI 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants</u>

The inspectors completed both Phase I and Phase II of the TI.

5. <u>Visual Inspection of Plant Systems, Structures, and Components in Containment</u>

a. <u>Inspection Scope</u>

The inspectors performed visual inspections of the interior of the Farley Unit 2 containment on March 24 and 25, 2004, during Refueling Outage 16. This included observation of accessible portions of plant systems, structures, components, instrumentation lines, and electrical cables inside the containment to observe material condition and inspect for aging conditions that might not have been previously recognized and addressed in the License Renewal Application. The following is a partial list of equipment observed:

- Main steam and feedwater systems pipe supports
- Personnel and equipment hatches
- SGs “A”, “B”, and “C” supports
- CS spray headers and piping
- Ventilation ducting
- Electrical cables and and supports
- Instrumentation lines, instrumentation, and supports
- “A”, “B”, and “C” reactor coolant pump cubicles/loop rooms
- Containment electrical penetrations
- Accumulator tanks
- Pressurizer relief tank
- Containment piping penetration area
- Containment liner and coatings

The observations of general material conditions included inspection of piping components for evidence of leaks or corrosion, inspection of coatings (piping, tanks, and structural components), and inspection of electrical cables and instrumentation lines for indications of deterioration. The inspectors also examined the containment tendon gallery.

b. Findings

No findings of significance were identified. The material condition at Farley was good and no significant aging management issues were identified.

4OA6 Meetings, Including Exit

1. Exit Meeting Summary

On April 1, 2004, the inspectors presented the inspection results to Mr. Don Grissette and the other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

2. Annual Assessment Meeting Summary

On April 13, 2004, the NRC’s Chief of Reactor Projects Branch 2 and Senior Resident Inspector assigned to the Joseph M. Farley Nuclear Plant (FNP) met with Southern Nuclear Operating Company to discuss the NRC’s Reactor Oversight Process (ROP) and the NRC’s annual assessment of FNP safety performance for the period of January 1, 2003 - December 31, 2003. The major topics addressed were: the NRC’s assessment program and the results of the FNP assessment. Attendees included FNP site management, members of site staff, corporate management and staff, and members of the local news media. This meeting was open to the public. Information used for the discussions of the ROP is available from the NRC’s document system (ADAMS) as accession number ML041050628. ADAMS is accessible from the NRC Web site at *http://www.nrc.gov/reading-rm/adams.html*.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

R. V. Badham, Security Manager
C. L. Buck, Chemistry/Health Physics Manager
R. M. Coleman, Outage and Modification Manager
D. E. Grissette, Plant General Manager
J. R. Johnson, Assistant General Manager - Operations
R. R. Martin, Operations Manager
B. L. Moore, Maintenance Manager
C. D. Nesbitt, Training and Emergency Preparedness Manager
W. D. Oldfield, Quality Assurance Supervisor
C. D. Collins, Nuclear Support General Manager, Farley Project
R. J. Vanderbye, Emergency Preparedness Coordinator
T. Youngblood, Assistant General Manager, Plant Support
P. Crone, Licensing Supervisor
P. Harlos, Health Physics Superintendent
T. Livingston, Chemistry Manager
R. Wells, Operations Shift Superintendent

NRC personnel

C. Casto, Division Director, Division of Reactor Projects
B. Bonser, Chief, Reactor Projects, Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000348/2004002-01	NCV	Inadequate procedure for electrical separation of single cell battery charger and safety-related battery (Section 1R13)
05000345,364/2004002-02	NCV	Failure to perform ASME code repair or non-code repair alternative of service water system ASME Class 3 piping (Section 1R15)

Closed

2515/150 (Docket 50-364)	TI	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009) (Section 4OA5.1)
2515/152 (Docket 50-364)	TI	Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02) (Section 4OA5.2)

Discussed

2515/153 (Docket 50-364)	TI	Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (Section 4OA5.3)
2515/154	TI	Spent Fuel Material Control and Accounting at Nuclear Power Plants (Section 4OA5.4)

LIST OF DOCUMENTS REVIEWED

Section 1R08: Inservice Inspection Activities

Procedures
FNP-100.26, Visual Examination, VT-1C,
FNP-100.27, Visual Examination, VT-3C
FNP-100.25, Visual Examination VT-3 for IWE Components, Version 2.0, dated 12/1/2000
FNP-100.43, Manual Ultrasonic Examination of Full Penetration Ferritic Piping Welds (Appendix VIII), Version 3.0, dated 10/9/2003
FNP-100.44, Manual Ultrasonic Examination of Full Penetration Austentic Piping Welds (Appendix VIII)
FNP-2-STP-167, Containment Integrity Examination, Rev 1, dated 2/1/2000
FNP-2-STP-609, Containment Tendon Surveillance Test, Rev 8, dated 5/19/2000
Wes Dyne QA Procedure WDP-9.2, Qualification and Certification of Personnel in Non Destructive Examination, Rev. 3, and Field Changes 1, 2, & 3, dated 3/5/2004

Other Documents
Drawing number D-206155, Containment Liner Floor Plan and Details, Rev. 3
Drawing number D-206157 Containment Liner Plan Section and Details, Rev. 17
Drawing number D-206158, Containment Liner Typical Details, Rev. 4
Drawing number D-206201, Floor Plan at Elev 105’-6" (Fill Slab) Reinforcing - Containment, Rev. 12
Letter number NL-03-1259, Risk-Informed Inservice Inspection Program, ASME Category B-F, B-J, C-F-1, and C-F-2 Piping, dated July 17, 2003
Safety Evaluation Report dated March 9, 2004, TAC Nos. MCO 178 and 179, Risk-Informed Inservice Inspection - ASME Code B-F, B-J, CF-1, and CF-2 Piping
PDI Protocol PDI-UT-1, Tables 1 and 2, and PDI Protocol PDI-UT-2, Tables 1 and 2
Visual Inspection (VT-3) reports for 15 pipe supports
Ultrasonic examination reports for weld numbers APR2-2100-1, APR2-4501-5 and APR2-4503-17
Indication Evaluation Report (IER) 001, Visual Indication on RPV Washer # 30
IER 002, Damage to Spring Can
IER 017, Evidence of Leakage on RCP Seals

Section 1R11: Licensed Operator Requalification
EIP-9.0, Emergency Classification and Actions
FNP-1-EEP-0, Reactor Trip or Safety Injection
FNP-1-EEP-3, Steam Generator Tube Rupture
FNP-1-AOP-2.0, Steam Generator Tube Leakage

FNP-1-AOP-34.0, Malfunction of RCS Wide Range Pressure Indication

Section 1R14: Personnel Performance During Non-Routine Plant Evolutions
FNP-1-EEP-0, Reactor Trip or Safety Injection
FNP-2-UOP-3.1, Power operation

Section 1R19: Post Maintenance Testing
FNP-2-STP-24.1, 2A, 2B, and 2C Service Water Pump Quarterly Inservice Test
FNP-0-AP-52, Equipment Status Control and Maintenance Authorization
FNP-1-STP-80.2, DG 1C Operability Test
FNP-0-EMP-1313.03, Maintenance of Siemens-Allis 4.16KV Breakers Type MA-350,

Section 1R20: Refueling and Outage Activities
FNP-2-UOP-4.1, Controlling Procedure for Refueling
FNP-2-UOP-4.3, Mid-Loop Operations
STP-40.0, Safety Injection with Loss of Off-Site Power
FNP-0-AP-94, Outage Nuclear Safety
FNP-0-UOP-4.0, General Outage Operations Guidance