UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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April 30, 2001

Southern Nuclear Operating Company, Inc.
ATTN: Mr. H. L. Sumner, Jr.
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P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: EDWIN I. HATCH NUCLEAR POWER PLANT - NRC INSPECTION REPORT NOS. 50-321/00-10, 50-366/00-10

Dear Mr. Sumner:

On February 26 through March 16, 2001, the NRC conducted a team inspection at your Hatch Nuclear Plant regarding your application for license renewal for the Hatch, Units 1 and 2 reactor facilities. The enclosed inspection report presents the results of that inspection. The results of this inspection were discussed on March 16, 2001, with members of your staff in an exit meeting open for public observation at the Hatch site.

The purpose of the inspection was to examine a sample of plant equipment to assess aging effects and to review the documentation of your aging management programs that support your application for renewed operating licenses for the Hatch facilities. The inspection methods utilized were to inspect visually a sample of plant equipment, review selected procedures and representative records, and to conduct interviews with plant staff regarding your Aging Management Programs.

This inspection concluded that the existing aging management programs were being conducted as described in your License Renewal Application. The inspection found that your plans regarding expansion of existing programs and creation of new aging management programs were consistent with your License Renewal Application. The inspection was unable to judge completely the acceptability of your new aging management programs due to their incompletion. Inspectors made comments on your proposed procedures for implementing aging management programs. Plant staff agreed to consider the NRC comments during procedure completion. Where appropriate, the NRC will review the final procedures during future inspections to ensure their adequacy.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection 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,

/RA/

Charles A. Casto, Director
Division of Reactor Safety

Docket Nos.: 50-321, 50-366
License Nos.: DPR-57, NPF-5

Enclosure: NRC Inspection Report Nos. 50-321/00-10, 50-366/00-10 cc:

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*See attached concurrence sheet and **E-Mail concurrence sheets

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-321, 50-366
License Nos:	DPR-57, NPF-5
Report No:	50-321/00-10, 50-366/00-10
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	E. I. Hatch Nuclear Power Plant, Units 1 & 2
Location:	P. O. Box 2010 Baxley, Georgia 31515
Dates:	February 26 - March 16, 2001
Inspectors:	B. Crowley, Reactor Inspector M. Scott, Reactor Inspector K. Van Doorn, Reactor Inspector H. Wang, Operations Engineer, NRR W. Burton, Project Manager, NRR
Approved by:	Caudle Julian Team Leader Division of Reactor Safety

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SUMMARY OF FINDINGS

IR 05000321-00-10, IR 05000366-00-10; 2/26-3/16/2001; Southern Nuclear Operating Company, E.I. Hatch Nuclear Power Plant, Units 1 & 2. License Renewal Inspection Program, Aging Management Programs.

This inspection of License Renewal activities was performed by four regional office engineering inspectors, and two staff members from the office of Nuclear Reactor Regulation. The inspection program followed was NRC Manual Chapter 2516 and NRC Inspection Procedure 71002.

The inspectors reviewed Aging Management Programs for selected plant systems as described in Appendix A of this report to determine if the program requirements were identified correctly and being implemented for the selected systems consistent with the Hatch Nuclear Plant License Renewal Application (LRA) and the NRC report “Safety Evaluation Report With Open Items Related to the License Renewal of the Edwin I. Hatch Nuclear Plant, Units 1 and 2" (SER) dated February 7, 2001. Where existing programs are to be expanded or new aging management programs are to be created to support the LRA, the inspectors examined available documentation and discussed future plans with applicant engineers.

This inspection concluded that the existing aging management programs were being implemented as described in the LRA. Discussion with plant staff and review of proposed procedures for expansion of existing programs and creation of new aging management programs demonstrated that plans were consistent with the LRA and SER. The inspectors had a number of comments on proposed procedures for potential improvements. The applicant was responsive to the NRC comments. The inspection was unable to judge completely the acceptability of planned new aging management programs due to their incompletion. Where appropriate the NRC will review the completed procedures during future inspections.

During this inspection the inspectors found some minor errors in existing plant procedures. The applicant promptly placed these issues in their corrective action system for resolution. (See Sections III.1 and IV.3)

The inspectors performed numerous visual inspections on portions of plant equipment to attempt to observe aging effects. The overall condition of plant equipment was good with certain exceptions. These included various corroded pipe supports in the intake structure associated with the Plant Service Water and RHR Service Water systems and, on the Diesel Generator building roof, extremely rusted Diesel Generator exhaust silencers, and Cardox fire suppression piping, valves, and bolting. (See Section I.B.6) These observations challenged confidence in the effectiveness of existing aging management programs for that equipment.

Appendix A of this report lists the plant systems selected for inspection and the corresponding Aging Management Programs credited by the LRA to manage aging in those systems. Appendix B contains a list of pertinent documents reviewed during this inspection and a list of acronyms appearing in this report.

REPORT DETAILS

I. Observation of Plant Material Conditions

A. Inspection Scope (71002)

In October 2000, during the Unit 1 outage, two inspectors from the Team performed walkdown inspections of accessible portions of several plant systems inside the Drywell and open portions of normally restricted areas. The objective was to determine the condition of plant equipment that is normally inaccessible during plant operation. Many of the applicant's test and inspection activities observed during the outage are to be parts of the applicant's Aging Management Programs (AMPs). Some of the observations involving inservice inspection of items in the Drywell were discussed in Inspection Report 50-321, 366/00-05.

Also, on January 19 - 21, 2001, an NRC inspector observed applicant personnel performing a Unit 2 radiographic inspection (RT), of PSW piping that had been selected for condition evaluation. During the February 26-March 16, 2001 portion of this inspection, the inspectors toured various portions of the plant to observe equipment condition.

Inspectors performed visual (walkdown) inspections of accessible portions of the following systems inside the Drywell, Reactor Building, and Service Water Structure:

- High Pressure Coolant Injection (HPCI)
- Core Spray (CS)
- Main Steam (MS)
- Residual Heat Removal (RHR)
- Residual Heat Removal Service Water (RHRSW)
- Plant Service Water (PSW)
- Drywell coatings and interior attachments
- Control Rod Drive (CRD)
- Standby Liquid Control (SLC)
- Reactor Recirculation (RR)
- General Drywell electrical cabling
- Feedwater (FW)
- Torus condition

B. Inspection Findings

1. Drywell Interior and Torus Exterior/Interior Observations

The Drywell is a sealed metal chamber that encloses the reactor vessel. The Drywell has piping penetrations for various services, safety-related systems, and power generation systems. The Drywell has open piping connections on the ports to the Torus, which is a metal ring-shaped structure surrounding the Drywell and containing the suppression pool water.

The inspectors accompanied applicant personnel on inspections of the Unit 1 Drywell and exterior of the Torus. Separately, prior to this Drywell entry the inspectors had reviewed visual documentation on certain major interior surfaces and therefore were aware of the coating conditions during the previous outage. The applicant had routine periodic photographic records of the condition of the Drywell and interior Torus coatings. It was apparent from ongoing work in the Drywell that the applicant was continuing to maintain the coating integrity. Due to previous maintenance and good original coating adhesion there were minimal problems with the Drywell interior coatings. The applicant had inspection procedures to document their findings or, in the case of the Torus interior, contractors provided documentation of the coating status.

During plant construction, concrete was poured in the base of the inverted light bulb shaped chamber (liner) of the Drywell to create a floor. The poured concrete in the lower Drywell has been beveled at its upper diameter forming a vee shaped notch between the steel Drywell wall and the concrete. The vee was filled with sealant. While on a Unit 1 inspection tour, the applicant and inspectors examined the concrete to liner joint in the lowest level of the Drywell. This joint, which has been wetted occasionally as, evidenced by stains on the liner above the joint, was repaired about five years ago. The applicant had epoxy coated the exposed joint prior to the sealant replacement application. Currently, the mastic sealant that was replaced in the bevel joint between the concrete and the liner is not completely adherent with the liner in places. The applicant used a depth ruler to measure where the sealant had lost adhesion with the epoxy coat. In spots, the pull away areas are nearly the full depth of the joint such that in time water could penetrate past the sealant. Where the pull away had occurred, the coating is intact behind the mastic except in one minor observed location approximately one inch in diameter. The small area exhibited minor corrosion. This spot appeared to have been the result of poor base metal preparation in the area. The applicant indicated that they had plans to replace the mastic within the next two refueling periods.

The material condition of the piping and components observed in the Drywell was good. In general, the equipment was clean with no evidence of system leakage. However a buildup of corrosion was observed on the insulated carbon steel PSW hangers and piping inside the Drywell. Although the Drywell is inerted with nitrogen during plant operation, the piping to the Drywell cooler had been exposed to moisture and oxygen probably introduced during outage periods. The applicant had entered the piping deterioration problem into their corrective action program (CR 9072, MWO 10003337) for evaluation. Worst case leakage of this piping would be observed by the operators in sump level change and may require a plant shutdown for its repair. Evaluation by the applicant found the piping functional, but it required cleanup and exterior passivation.

During the Drywell inspections, the inspectors observed the general condition of electric cable connections to components and cabling in trays. The suspended cable was in acceptable condition. Several of the leads to instruments and components had been replaced in recent years. Nonetheless, from their appearance, these cables had been exposed to environmental and mechanical aging. Other cables in the vicinity of the reactor pressure vessel appear to be exposed to similar thermal and radiation environments. The inspectors looked at the condition of cable loose in trays and found no signs of cracking or loss of flexibility. Years of exposure to heat and radiation had changed slightly their color and general appearance.

Thermal insulation in the Drywell was in good condition. Where observed, the material appeared to meet the proper requirements. Due to the tightness of the space, several sections of the insulation were inevitably worn by human passage. Discussion with the insulation personnel indicated that a post outage inspection would be performed to repair these worn areas.

Inspections of the outside of the Torus revealed an intact coating system. The coatings have needed little attention during the life of the plant. The inspections performed by the applicant were intended to identify minor coating problems and other kinds of discrepancies. The Quality Control inspectors performing the inspection found a number of minor pre-existing problems, e.g., a tool had been dropped and gouged the paint, but no coating corrosion or peeling was observed. These were entered into the applicant's corrective action program.

The inspectors observed that a number of large exterior Torus hold-down fasteners were slightly bent. Due to the observed condition of the existing Torus protective coatings, which also protected the fasteners, the inspectors surmised that the condition must have existed for a long time. The applicant stated that the coatings had never been altered since construction. Several of the flat washers under the foundation fasteners were split or ground off. Several of the retaining nuts to these retention elements were slightly loose. The applicant had previous documentation that evaluated the acceptability of these conditions.

2. Class C Service Water Piping

As for aging management of the RHRSW and PSW system carbon steel piping, the applicant credits their piping inspection programs for managing the effects of internal corrosion, erosion, and fouling. This was addressed in the License Renewal Application (LRA) under Final Safety Analysis Report Supplement A.1, Existing Programs and Activities. Locations determined to be prone to corrosion are infrequently used piping, piping with low fluid velocity, small diameter piping, backing rings and socket welds. The PSW and RHRSW Inspection Program was developed using the ASME, Section XI program for the Inservice Inspection Program as a model. The framework for the program is also based partially upon Generic Letter 89-13 and its supplements, and NUREG-1275, Volume 3, "Operating Experience Feedback Report –Service Water System Failures and Degradations." Minimum wall thickness is calculated in accordance with the piping design code, piping stress requirements and the piping specification drawings. The bases for the acceptance criteria are contained in the existing PSW and RHRSW Inspection Program procedures. By code, the applicant does not have to volumetric test to evaluate the ASME Class C piping.

The inspectors observed outage work and evaluative inspections in the plant. During the outage the applicant was actively working open systems and replacing components and piping. The inspectors had the opportunity to inspect a open RHR heat exchanger, CS and RHR room cooler cooling coils, replacement of a PSW strainer, and removal and replacement of a section of PSW piping from a CS and RHR room cooler (location 633 A).

The inspectors reviewed an evaluation performed previously for the pipe section in January 2000. The pipe wall had a localized area less than minimum wall which placed it in the applicant's action level required range. By procedure, the piping had been evaluated for a reduced minimum wall and scheduled for work. The evaluation had stated that the pipe was acceptable for use until September 2000 (an expected outage time frame). In October 2000, the piping had developed a spraying leak after the plant had been shut down and as system flow conditions were being altered, causing an induced pressure spike. In this case, the observed pipe section had multiple locations where the micro biologically induced corrosion and general corrosion had thinned the pipe wall. Under the applicant's program, targeted and identified locations are examined periodically with ultrasonic testing for wall thinning. The sampled locations may or may not identify the thinnest wall but would be indicative generally of the sections' condition.

The piping remained intact for one month longer than the evaluation period allowance. Although the pipe remained operable with the spraying leak and was still capable of fulfilling its function, the predicted life of the piping section was very close to its actual end-of-life. As a conservative action, the applicant replaced the entire piping run during the Unit 1 cycle 19 outage.

The inspectors concluded that the applicant was informed and knowledgeable about SW piping condition. Sections of buried piping from the intake structure to the equipment in the Reactor Building were not inspected directly, but visual inspections were conducted informally above ground looking for indications of water upwelling. The applicant had been aggressive in replacement of piping in the intake structure around both types of SW pumps. The applicant was replacing the RHRSW strainers in the intake structures, which should reduce out-of-service times on the trains and facilitate maintenance. The applicant had plans to replace the traveling screen parts to improve their serviceability and reliability.

3. Outage Accessible Components and Structures

During this same week in October 2000, the inspectors, concentrating on structural aging, toured several areas with applicant engineers to evaluate the condition of the structures. The inspectors conducted walkdowns of the diesel building, portions of the reactor building for both Units, the exterior of the reactor buildings, and the Unit 1 “diagonal room” with a disassembled RHR heat exchanger and HPCI room coolers with removed insulation. The diesel building interior concrete was in excellent shape with no observable settlement cracks or sign of aging duress. Overall, the components and structures were found to be in acceptable condition.

In the outage Unit, many of breaker cabinets and cubicles were open in various spaces. The applicant was performing preventive maintenance (PM) on these items. The electrical components and motor control center door seals appeared to be in good repair. Bolt and hanger support for electrical gear in the spaces was in adequate condition. Motors for the CS and RHR pumps were being replaced under a ten year PM. Cooling coils on the operating HPCI room cooler were uniform in temperature over the coil stack height, indicating no flow blockages. There were no signs of piping or instrument degradation where the piping insulation had been removed.

In addition to the walkdown inspections performed during the October 2000 Unit 1 Cycle 19 outage, in March 2001 the inspectors performed walkdown inspections of accessible portions of the control rod drive and standby liquid control systems for Units 1 and 2. In general, the material condition observed for these systems and components was good with no evidence of system leakage. However, a few feet of Unit 1 control rod drive system 1-1/2" (drive water pressure control) and 2" (test bypass) piping on the 130" elevation of Unit 1 had some foreign substance (hard black/gray material) on the surface. There was also some evidence of minor corrosion associated with some of the foreign material. The applicant issued Condition Report (CR) 2001002003 to investigate this condition and take appropriate corrective action.

4. Observation of Inservice Inspection Activities

In October 2000, during the Unit 1 outage, the inspectors observed certain planned ISI inspections which were being performed in accordance with the existing ISI program referenced in the LRA. During observation of the ISI activities, the general condition of the plant equipment was inspected. In-process NDE inspections were observed for the following ISI components:

RPV Head Welds 1B11\HC-1-G and 1B11\HC-1-H
B Loop Recirculation Inlet Nozzle 1B11\N2E
RPV Head Nuts and Washers 1B11\NUT-19-24 and 1B11\WASHER-19-24
In-vessel Video Inspection of RPV General Structural Condition
In-vessel Video Inspection of Core Spray Piping and Components 1B11\N3AA, \N4AA, \N8AA, \N9AA, \N10AA, \N13AA, \N15AA, and \N179AC
In-vessel Video Inspection of Core Plate Components 1B11\G-28-13-1, 1B11\G-28-13-2, 1B11\G-49, and 1B11\P44
In-vessel Video Inspection of Jet Pump Components 1B11 I\J5N, \J5D, \J6N, \J6D, \J10N, \J13N, and \J5/6G
Core Spray Pipe Weld 1E21-1CS-10B-5
Reactor Water Cleanup Pipe Welds 1G31-RWCUM-6-D-8 and 1G31-RWCUM-6-D-10
Penetration X-3 (Drywell Dome Bolting) 28 - 33
Residual Heat Removal Pipe Hangers 1E11-1RHR-9A-HS-FB and 1E11-1RHR-9A-HS-1
Portions of the Drywell Liner and Mastic Seal

During Unit 2, Cycle 15 outage, in-process ISI NDE and in-process records were observed for liquid penetrant (PT) examination of three pipe welds; magnetic particle (MT) examination of one pipe support weld ; ultrasonic (UT) examination of eight pipe welds; and review of completed videos for Visual (VT) examinations of five in-vessel components. (see NRC Inspection Report 50-366/00-02, Section M1.2, for documentation of these inspection activities)

ISI activities were being performed in a quality manner using qualified procedures and personnel. The material condition observed for these systems and components was good. In general, the equipment was clean with no evidence of system leakage.

The team also reviewed the following (most current) ISI outage plans and reports for each unit:

Inservice Inspection Outage Plan, Edwin I. Hatch Nuclear Plant Unit 2, 2000 Spring

Inservice Inspection Outage Plan, Edwin I. Hatch Nuclear Plant Unit 1, 2000 Fall

Inservice Inspection Examination Records Final Report, 2000 Spring Refueling Outage (2R15)

Inservice Inspection Final Report, Edwin I. Hatch Nuclear Plant Unit 1, 2000 Fall

The outage plans and reports were sampled to verify that the systems and components, for which the LRA credited the ISI Program for aging management, were included.

The team concluded that ISI activities were being conducted as described in the ISI Program and were effective. The program included the systems and components listed in the LRA, for which the LRA credited the ISI Program for aging management.

5. Observation of Plant Service Water Radiographic Inspections

During the January 19 - 21, 2001 time frame, an inspector observed a Unit 2 radiographic inspection (RT) of PSW piping that had been selected for evaluation. The inspections were carried out by vendor personnel, site system engineering, and corporate ISI personnel in accordance with Plant Service Water and RHR Service Water Piping Inspection Procedure, 42IT-TET-012-2S, Revision 3. Of the 28 RT sample locations (two film exposures per location, 90 degrees apart), the inspector observed portions of the setups for RT and observed the health physics controls. Further, the inspector observed about 25 of the radiographic film sets and sampled data reduction efforts. The applicant demonstrated proper methodology in all activities. In all observed instances the RT revealed piping that was not functionally occluded nor had excessive wall thinning. The inspector did observe two locations that showed evidence of wall thinning and, under their program, the applicant took programmatic actions to investigate further.

There was a minor weakness to the program in that the historical pipe replacement status of the PSW piping was difficult to access. The extensive service water systems cool many safety and non-safety related components in the plant whose failure can challenge the plant's operation. The applicant has had to review past evaluation report packages and replacement work packages to select each year's RT sample points. There are no chronologically marked up piping diagram(s) or a compiled computer data set to readily display and track system piping degradation or piping replacement status. The accompanying personnel were aware of the various ages of the different piping sections or could retrieve the data for any pipe section in question given time for the research. During the inspection, the inspector walked down the majority of the Unit 2 PSW piping while the plant was at 100 percent power and found the systems in good condition. Therefore, the stated weakness is minor.

The applicant sampled four locations that had not previously been selected for RT. None of these locations met the applicant's action levels for required repair. The methodology and technique used to sample PSW pipe condition appeared to be adequate to maintain the small diameter pipe that can be radiographed.

6. Observation of Plant Equipment Outdoors and in PSW Intake Structure

During the walkdown inspections in February 2001, the inspectors noted a number of components which had varying degrees of corrosion and were not being maintained by the protective coatings program. These included various corroded pipe supports in the intake structure associated with the PSW and RHRSW systems, corroded hold down bolts on the Diesel building Cardox unit, and, on the Diesel Generator building roof, extremely rusted Diesel Generator exhaust silencers, and Cardox fire suppression piping, valves, and bolting. One silencer, 2A, was significantly corroded and, in fact, the exhaust pipe associated with the silencer was cracked for approximately 75% of its circumference and was about to collapse. The applicant had recognized previously the problem with corroded supports at the intake and had initiated corrective action, however, the other problems on the diesel building roof had not been identified previously. The applicant plans to address the fire protection systems via the fire protection programs and the other areas by either the Structural Monitoring Program or the Protective Coatings Program. The existing Protective Coatings Program appears capable of appropriately addressing these issues, if applied to this equipment.

C. Conclusions

These visual inspections found the mechanical systems to be well maintained and in generally good condition. The inspectors observed external corrosion on the carbon steel Plant Service Water piping inside the reactor building. There were only minimal problems with the Drywell interior coatings. The team also observed generally good condition of electrical cabling in the Drywell, with some limited aging effects, and evidence of periodic applicant activity in previous instrument and component cable replacement. The inspectors toured the intake structure, portions of the reactor buildings and safety-related equipment rooms, Torus areas, Diesel building and roof. The structures were found to be in acceptable condition. The inspectors observed substantial corrosion on pipe supports in the lower levels of the intake structure and on equipment exposed to weather on the diesel building roof. These observations challenged confidence in the effectiveness of existing aging management programs for that equipment.

II. Review of Mechanical Aging Management Programs

A. Inspection Scope (71002)

The team reviewed selected aging management programs, to verify that the existing programs were implemented consistent with the information presented in the applicant's License Renewal Application (LRA) and the NRC report "Safety Evaluation Report With Open Items Related to the License Renewal of the Edwin I. Hatch Nuclear Plant, Units 1 and 2" (SER) dated February 7, 2001. Where existing programs are to be expanded or new aging management programs are to be created to support the LRA, the team examined available documentation, reviewed past inspection data if available, and discussed future plans with applicant engineers.

The applicant has developed a license renewal Commitment Implementation Plan to provide a process and schedule to implement license renewal commitments into existing or future on-site procedures, and to allow for management oversight of the implementation process. The plan consists of tasks designed to identify license renewal commitments and incorporate the commitments into a matrix; draft revisions to procedures, or create new procedures, when needed; update the matrix in response to changes in commitments; conduct personnel training on the commitments; and perform a procedure walk-though after the commitments have been fully integrated into plant procedures before turnover to plant operating staff.

The commitment matrix reflects commitments identified in aging management programs discussed in Appendix A of the LRA, and identifies the procedures which will incorporate the commitments. The matrix also documents instances where license renewal commitments must be implemented through new procedures. In response to requests for additional information from the NRC staff regarding the AMPs described in Appendix A of the LRA, the applicant submitted to the NRC Appendix B of the LRA on October 10, 2000. Appendix B contains much more detailed descriptions of AMPs than Appendix A. The commitment matrix does not currently reflect additional commitments identified in Appendix B. Any additional commitments identified in Appendix B will be added to the commitment matrix when it is updated soon.

In addition, for most AMPs, the applicant had already prepared proposed revised plant procedures to incorporate the license renewal commitments. The inspectors reviewed some of the proposed procedures and commented on them where appropriate.

B. Inspection Findings

1. Boiling Water Reactor Vessel and Internals Program

The Boiler Water Reactor (BWR) Vessel and Internals Program is credited in the LRA as an aging management program for the following reactor pressure vessel (RPV) internal components: shroud and shroud repair hardware, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, top guide, and dry tubes. The program is credited for managing cracking in internals components due to various mechanisms. The LRA defines the Boiling Water Reactor Vessel and Internals Program as consisting of various Boiler Water Reactor Vessel and Internals Project (BWRVIP) programs and the ASME Section XI Inservice Inspection Program. The BWRVIP is an association of utilities formed to focus on resolution of BWR vessel and internals issues. The BWRVIP developed inspection and evaluation reports for internals components and submitted them to the NRC for review and approval. The reports address current term and license renewal. The applicant has committed to implement the requirements of the BWRVIP reports as final NRC SERs are issued, or notify the NRC if the BWRVIP requirements are not implemented. The BWRVIP programs taken credit for in the LRA for aging management have been submitted to the NRC and are in various stages of review and approval. Only two BWRVIP reports (27 and 49) currently have final NRC SERs issued.

In addition to discussion of the overall BWR Vessel and Internals Program with responsible applicant personnel, the inspectors reviewed the following BWRVIP reports and the ASME Section XI ISI Program applicable to aging management for RV internals at Hatch and verified that the applicable inspection and evaluation requirements have been implemented:

Shroud (including repair hardware)	-	BWRVIP-76
Shroud Support	-	BWRVIP-38
Core spray Piping and Sparger	-	BWRVIP-18
Top Guide	-	BWRVIP-26
Control Rod Guide Tube	-	BWRVIP-47
Jet Pump Assembly	-	BWRVIP-41
CRD Housing	-	ASME Section XI
Dry Tube	-	ASME Section XI

Although the BWRVIP reports have not had NRC final SERs issued, the applicant’s policy has been to implement the BWRVIP requirements as the reports are published. The implementing method has been to include the BWRVIP requirements for the various internals components in the ASME Section XI ISI Program.

In addition to verification that required internals components were included in the ISI Program, the inspectors reviewed the most recent ASME Section XI Outage Plans and Reports as detailed in paragraph I.B.4 above and verified on a sampling basis that the plans and reports included the internals components identified in the LRA as requiring aging management. Also, as noted in paragraph I.B.4 above, the inspectors observed in-process inspection of a number of internals components during the Unit 1 Cycle 19 and Unit 2 Cycle 15 outages.

The inspectors concluded that BWRVIP requirements referenced in the LRA for RPV internals were being implemented through the ISI Program. However, no written Boiling Water Reactor Vessel and Internals Program document had been compiled to specify how BWRVIP requirements are extracted from the BWRVIP reports and detailed in site specific documents. Although no problems were identified with implementation, the inspectors concluded that an experienced and knowledgeable applicant staff contributed to successful implementation, and that, for continued future successful implementation, a written program was needed. The applicant agreed with this conclusion and stated that a written program document would be developed.

2. Reactor Pressure Vessel Monitoring Program

The Reactor Pressure Vessel Monitoring Program is credited in the LRA as an aging management program for the following components: RPV shell and closure head; nozzles, appurtenances, and penetrations; attachments and connecting welds (brackets and lugs); and RPV head closure studs. The aging effects are cracking and loss of fracture toughness. The LRA defines the Reactor Pressure Vessel Monitoring Program as consisting of various BWRVIP programs and the ASME Section XI Inservice Inspection Program. (see paragraph II.B.1 above for a description of the BWRVIP and the applicant's commitment to the BWRVIP requirements).

In addition to discussion of the overall Reactor Pressure Vessel Monitoring Program with responsible applicant personnel, the inspectors reviewed the following BWRVIP reports and the ASME Section XI ISI Program applicable to aging management for the reactor pressure vessels at Hatch and verified that the applicable inspection and evaluation requirements have been implemented:

Shell and Head	-	BWRVIP-74
Nozzles (including safe ends and thermal sleeves)	-	BWRVIP-74
Appurtenances	-	BWRVIP-74 and ASME Section XI
Penetrations	-	BWRVIP-27
Attachments and Connecting Welds (including shroud support weld, jet pump pad weld, closure studs, and support skirt)	-	BWRVIP-38 BWRVIP-41 BWRVIP-48 BWRVIP-74

BWRVIP-74 is the overall controlling document for aging management of the RPV. It references the other listed BWRVIP reports and describes other RPV requirements such as fracture toughness requirements to meet 10 CFR 50 Appendices G and H and NUREG - 0619 requirements for inspection for cracking in feedwater nozzles and control rod drive return drain line nozzles. The implementing method has been to include inspection requirements of BWRVIP-74 and referenced documents in the ASME Section XI ISI Program.

When questioned about aspects of the program other than inspection activities, such as fracture toughness, the only implementing procedure identified by the applicant was site Surveillance Procedure 42SV-B11-002-1S, Revision 1, Reactor Material Irradiation Specimen Surveillance. This procedure required removing and testing specimens 10 years after initial startup and again at approximately 15 Effective Full Power Years. The surveillance has been completed for Unit 1 and the 10 year specimens have been removed for Unit 2. No procedures were identified for specimen handling and testing after completion of the existing surveillance procedure. BWRVIP-74 discussed a proposed integrated surveillance program (ISP) where surveillance specimen data and availability from all of the BWR plants are analyzed and incorporated into an integrated program to improve the quality of data and compliance for the entire BWR fleet. This ISP is further described in BWR Integrated Surveillance Program Plan (BWRVIP-78). The applicant plans to implement the ISP at Hatch if approved by the NRC.

In addition to verification that required RPV components were included in the ISI Program, the inspectors reviewed the most recent ASME Section XI Outage Plans and Reports as detailed in paragraph I.B.4 above and verified on a sampling basis that the plans and reports included the RPV components identified in the LRA as requiring aging management. Also, as noted in paragraph I.B.4 above, the inspectors observed in-process inspection of a number of RPV components during the Unit 1 Cycle 19 outage.

The inspectors observed that, similar to the Boiling Water Reactor Vessel and Internals Program, there was no overall written Reactor Pressure Vessel Monitoring Program document to specify how BWRVIP requirements are extracted from the BWRVIP reports and implemented in site specific documents. The applicant agreed with this observation and stated that a written program document would be developed.

3. Reactor Water (RW) Chemistry Control

RW piping is filled from the Condensate Storage Tank (CST), which is in turn filled from the Demineralized water storage tank, and both tanks are maintained at relatively high water quality levels. Using an existing program, reactor water is maintained at high purity and tight chemistry controls during most plant operational modes. Aside from feedwater, fluid moves away from the RW piping and does not generally return to RW piping thus reducing chemistry contamination problems. Feedwater is cleaned up to a relatively high level of purity before it is introduced into the RW piping.

This AMP stemmed from an existing site program addressed in Technical Specifications (TS), Technical Requirements Manual (TRM), and industry documents such as the Electrical Power Research Institute guidance (e.g.,TR 112214 and TR-103515). The program's specific intent is to limit the effects of oxidative compounds that cause corrosion on the primary piping. As a part of verifying the implemented methodology, the inspectors reviewed the above documents against the existing credited program that was not generally changed by this AMP. The program was discussed with chemistry personnel from the general office and site. The inspectors verified that the values used in existing procedures were consistent with the above referenced documents and that the sampled chemistry data met procedure requirements. The control of chemistry was considered a mitigating strategy not intended to directly detect aging effects. These strategies have been recognized by the owners group as an effective program for mitigation of intergranular corrosion. The detection of aging effects is accomplished by other AMPs such as BWR Vessel Internals Program, Reactor Vessel Monitoring Program, and the Inservice Inspection Program discussed elsewhere in this report. As discussed earlier in this report and in NRC inspection reports 50-321,366/00-009 and 00-005, the inspectors walked down the visible portions of primary piping and observed recent ISI inspections, finding no physical or program problems.

4. Component Cyclic Or Transient Limit Program (CCTLP)

The CCTLP is generally described in Appendix B, Section B.1.12 of the LRA. This program is described in procedures 42SV-SUV-029-1S, Cumulative Fatigue Usage Factor Monitoring, Revision 5 and 42SV-SUV-029-2S, Cumulative Fatigue Usage Factor Monitoring, Revision 4; which require analysis of transient data for temperature and pressure changes and calculation of Cumulative Fatigue Usage Factor (CFUF) to confirm systems remain within ASME Code Section III fatigue limits. Additional actions are required if the calculated CFUF exceeds 1.0. Current requirements of the Technical Specifications only require monitoring of limiting locations for the reactor pressure vessel. For license renewal the applicant plans to monitor additional limiting locations to include the Torus and class 1 piping. Procedures have been modified to include these locations.

The inspectors reviewed the applicable procedures, reviewed current CFUF results including several 60 year CFUF projections, reviewed the applicants calculation methodology, and discussed the methodology and program attributes with the responsible personnel. Current projections indicate that CFUF will remain below 1.0 and the program was being implemented properly by the applicant.

5. Inservice Inspection Program

The ASME Section XI Inservice Inspection (ISI) program, an existing program, is credited in the LRA as an aging management program for ASME Class 1, 2, and 3 piping and components and Class MC components. The program also included augmented examinations to satisfy applicant commitments based on Generic Letters, NUREGS, etc. The LRA credits the ISI Program as an aging management program for portions of the following systems:

B11 - Reactor Assembly	B21 - Nuclear Boiler
B31 - Reactor Recirculation	E11 - RHR and RHRSW
P41 - PSW	T23 - Primary Containment
T52 - Containment Penetrations	

The program is credited for managing the loss of material and cracking in carbon steel, low alloy steel, stainless steel, and nickel base alloys due to various mechanisms. The Program consists of performing surface and volumetric nondestructive examinations (NDE) of piping and components at various intervals in accordance with the ASME Boiler and Pressure Vessel Code and other augmented requirements such as NUREGs, Generic Letters, BWRVIPs, etc. The ISI Program is controlled by E. I. Hatch Administrative Control procedure 40AC-ENG-001-0S, ASME Section XI Program, and the following program documents:

Inservice Inspection Program, Third 10-Year Interval, E. I. Hatch Nuclear Plant Units 1 & 2, Revision 6

Inservice Inspection Program, Third Ten-Year Examination Plan, E. I. Hatch Nuclear Plant Unit 1, Revision 5

Inservice Inspection Program, Third Ten-Year Examination Plan, E. I. Hatch Nuclear Plant Unit 2, Revision 6

These program documents are updated each 10-year interval and submitted to the NRC for approval of any relief requests. The current program (Third 10-year Interval) ends on December 31, 2005, and was approved by an NRC SER dated June 16, 1997.

In addition to discussion of the program with responsible applicant personnel, the inspectors reviewed completed records and observed in-process ISI activities as noted in section I.B.4 above and found them to be acceptable.

6. Residual Heat Removal (RHR) Heat Exchanger (HX) Augmented Inspection and Testing Program

These HXs sit idle most of the time. Their most common usage is that they are used to cool the plant during outages. They are flow tested on their raw water or RHRSW side quarterly and then flushed on a regular basis for biological control. The HXs are upright with stainless steel tubes capable of operating in the severe conditions of a steam condensing mode of use.

The new AMP expanded existing inspections that have been inspecting the tube side of the RHR HXs at regular intervals during outages. Existing procedure RHR Heat Exchanger Preventive Maintenance, Revision 3 ED 1, 52PM-E11-009-0S, inspected the HX end cover and tubes. Further, the procedure cleaned the tubes using air pressure. The inspectors had observed eddy current testing of the 2A RHR HX during the October outage that occurred while the applicant was performing the above preventive maintenance (PM) work. As a part of verifying the AMP function, the inspectors reviewed proposed details of new procedures. The proposed procedure provided: inspection intervals for visual inspection of the opened HX; cleaning of the tubes and HX open end; shell side inspections; and eddy current tube examination. The frequencies were based on previous PM schedules and operating experience. The details of shell side HX entry and mode of inspection have yet to be developed. Under the new program, there was no specified frequency of leakage testing. This was indicated to be based on the review of previous collected inspection results or operation data. The frequencies stipulated in the application's LRA Appendix B were as follows:

Testing Type	Appendix B	Procedure
Eddy current Testing	10 years	10 years
Visual Inspection of HX tube side	three cycles	54 mos
Visual Inspection of HX shell side	10 years	10 years

The operating experience mentioned above may change the frequencies. The visual inspection is "three cycles" in length that is undefined in the appendix but was explained by the applicant to mean three refueling cycles. Refueling cycle length is to increase from 18 months to 24 months such that the frequency would be six years (while the procedures indicated 4.5 years). This may require on-line HX inspections under their TS Limiting Condition of Operation time limits. These suggested frequencies appear reasonable with the caveat that a change in refueling frequencies may change the inspection schedule.

The inspectors reviewed the proposed procedure for HX inspection. This procedure had yet to be reviewed by the site staff. The LRA Appendix B and proposed acceptance criteria contained limited detail. The criteria were generally left to the procedural indicated inspectors to determine an undefined "significance" level. Further, the proposed procedure did not indicate the proposed inspector qualifications. Chapter 17 of the applicant's UFSAR discussed the requirements of ASME N45.2.6 and ANSI N18.7 - 1976/ANS-3.2 as they relate to inspector qualifications for general maintenance activities. The applicant agreed to review the acceptance criteria and inspector qualifications during further procedure development.

Per Appendix B of the application, site operating experience was reviewed. The Appendix indicated that in 1996 radionuclides had been found in a RHRSW or tube side of a HX and that nine leaking or suspected leaking tubes had been plugged. Per the Appendix, subsequent eddy current testing in 1998 on the same HX and in 1999 on another (same Unit) HX indicated no "significant" degradation. The inspectors reviewed reports concluding that three of the four HXs had been inspected and the fourth was due at the next refueling. As stated in the Appendix, there have not been known HX leaks since the 1996 event, and due to the original licensing conditions (RHRSW had no radiation monitors), the applicant has manually monitored the discharge of the RHRSW flume on a regular basis to evaluate potential leakage and support the annual dose release assessment. The inspectors understood that when the HXs are in service cooling the plant for outages the RHRSW pressure is about 20 psig greater than primary pressure. The augmented inspection AMP will determine the condition of the RHRSW HX on a routine basis. The inspectors concluded that the new program could be improved with the above mention considerations, and the existing program has been evaluating the heat exchangers' conditions on a routine basis and appropriately using the corrective action program.

7. Plant Service Water (PSW) and RHR Service Water Chemistry Control Program

For this AMP existing procedures and programs are identified as AMP items with no enhancements or additions needed. The program chemically treated both systems to mitigate corrosion problems. The applicable procedures are: 64CH-OPS-006-ON Plant Service Water and Circulating Water Treatment Systems, Revision 12 ED 2,; 34GO-OPS-024-1S Equipment Rotation and Flushing of PSW and RHRSW Piping Deadlegs, Revision 9 ED 1(Unit 1); and, 60AC-HPX-010-OS Chemistry Program, Revision 9 ED 3. As a part of verifying the implemented methodology, the inspectors reviewed the above procedures against the LRA Appendix B program statements and support documentation. Except for the second procedure, the deadleg flush, these procedures were altered by the applicant to indicate that they were part of the license renewal commitment base. The applicant agreed that they will either add those dead leg flushing procedures to their commitment list or will modify the chlorination procedure to clearly outline an acceptable methodology for RHRSW chlorination. The AMP is intended as a mitigative activity with no detection capability. The detection capability resides in the three other PSW and RHRSW AMPs for problem detection discussed elsewhere in this report.

8. Plant Service Water and RHR Service Water Inspection Program

This was an existing program that looked at the major portions of the effected systems. The AMP involved a proposed modified procedure, 40AC-ENG-013-0S, Plant Service Water and RHR Service Water Piping Inspection Program, Revision 3 ED 2, that would tie the existing procedures into the program. The inspectors had observed previously the realtime activities of the program during the October 2000 refueling (report 50-321, 366/00-009) and during radiographic inspections discussed elsewhere in this report. The main thrust of the program was to detect wall thinning, surface indications, and reduction in flow cross section. There are adjuncts to the program that provide further assurance that these systems continue to perform their function. It should be noted that the main effort of this program is outside certain regulatory requirements, but systems monitoring is within the scope of the maintenance rule.

The above instruction as well as the existing program procedure, 42IT-TET–12-XS, used radiographic and ultrasonic testing (RT and UT, respectively) to detect problems in mainly six inch and smaller diameter piping. RT had been used up to 8 inch diameter pipe. UT is used infrequently on larger diameter piping. Should either of the non-destructive tests reveal problems, the applicant can perform flow or other tests to assess conditions.

The large bore buried piping is not in the program per se. The reason for this is that the larger pipe at Hatch has no extensive corrosion-related history of problems. There was one failure of a large bore pipe early in the plant's history that was due to construction problems. It was theorized that an object was drug across the pipe prior to burial thus gouging the protective coating. Large bore pipe flowing river water with velocities higher than 3 feet per second have not been identified as having general industry leakage problems to date. This particular buried piping has no welded on components such as tees or piping wall changes in the buried sections that would exacerbate erosion or corrosion. Further, the historical industry wide corrosion problems, when they have occurred, have been found by surface leakage prior to flow degradation occurring. During an October 2000 outage, the applicant had the opportunity to inspect several feet of open end large bore pipe while replacing system strainers. As reported, the exposed internals were coated with passive dark slime and had none of the distortions brought on by biological attack.

The remainder of the applicant's program consisted of diver inspections of the river intake structure and the PSW and RHRSW pump flow testing. The inspectors reviewed the diver inspection procedure and found it acceptable. The pump surveillances are required by the approved regulatory programs and are reviewed regularly by the NRC Resident Inspectors.

Outside of the proposed AMP, the licensee has PSW flow confirmation procedure 42EN-ENG-033-1S, PSW Flow Model Confirmation Data Collection, Revision 0 ED 1, that evaluated flow at the many branch supply points throughout the system. The inspectors reviewed results of the last two tests from the years 1999 and 2000, Units 2 and 1, respectively. This provided a reasonable flow balance test for the system. This data that is taken every three years validated current plant conditions, general PSW health, and indirectly corroborated AMP intended function. The applicant indicated that they would consider making this test part of the AMP. With its single purpose use, its flow measuring elements near the HXs, and its quarterly IST flow validation, no such procedure was needed for the RHRSW.

Additionally, the applicant performed regulatory required inservice pressure tests in accordance with ASME Section XI. At a 40 month frequency for the tests, the applicant performed inspections of the exterior of exposed piping looking for leakage. The applicant did not perform a documented above ground walkdown of the extensive buried PSW and RHRSW piping as a part of this test. The applicant indicated that they would consider documenting the walkdown of the nine sections of buried pipe that was approximately 200 yards in length (each piping run) during the test.

Another AMP, Passive Component Inspection Activities (PCIA), that is discussed in another section of this report impacted a portion this AMP. The applicant-proposed version of that program would inspect buried piping of certain systems, including the PSW and RHRSW, should the ground near the pipe be disturbed by digging. An existing procedure, 52GM-MME-028-0S, External Surface Coating of Underground Metallic Pipe, Revision 2, performed this activity and invoked the existing PSW and RHRSW testing (42IT-TET-012-XS) procedure for use when pipe is uncovered. In the PCIA section of the LRA, the applicant indicated that an alternate procedure would be utilized. Additionally, there was parallel Open Item (SER item number 3.1.13) on the buried PSW and RHRSW pipe inspection requirements should the piping be uncovered for maintenance.

9. Torus Submerged Components Inspection Program

The Torus, which contains the suppression pool, is partially water-filled and provides exhaust volume for the HPCI and RCIC turbines, Safety Relief Valves discharge lines and will accept a blow down of the primary system should a LOCA occur. The stainless steel components beneath the pool water and those in the vapor space above the water in the Torus will be inspected under the AMP. The inspection of the components of this AMP will be in accordance with a visual program similar to a VT-1 methodology of the ASME Section of the Boiler and Pressure Vessel Code. The applicant has a proposed procedure to accomplish the new inspection that appeared to be acceptable.

The Torus coated components inspections have been in place for a considerable period. These are not in the AMP but covered by another AMP (see Section IV.1 of this report). The inspectors examined the vendor's procedures that accomplished this inspection since 1997 and these appeared to be acceptable. The inspectors observed video tapes of the last two underwater inspections carried out by the vendor. These activities appeared to be acceptable demonstrating, when observed, that the stainless steel equipment was in good condition.

As a part of the coated component inspection, the same vendor as above desludged the Torus removing particles introduced by the use of the steam turbines, which were removed for Torus corrosion prevention on all components and chemistry maintenance. The reviewed procedures and attendant report were found acceptable.

10. Demineralized Water (DWT) and Condensate Storage (CST) Tank Chemistry control

This AMP controls the chemistry for these important tanks. The AMP is a combination of existing chemistry control procedures that utilized EPRI TR-103515 guidance. DWT provides makeup to most plant systems including the CST. Upon inspectors' review, the applicant's LRA Appendix B values of chemistry maintenance agreed with the EPRI guidance and agreed with the values found in the existing procedures. As with other chemistry AMPs, the controls do not measure directly aging effects, but control water purity to prevent potential degradation. The applicant had reviewed operating experience with the tanks involved and found no significant issues with only minor chemistry excursion problems. Inspectors' discussions on the tanks with the licensee revealed no new problems. The inspectors walked down one of the two tanks while onsite, finding some unknown material splatter and corrosion on the Unit 1 aluminum CST. The applicant was informed of the material buildup on the exterior of the tank. Without having the material buildup evaluated, the overall condition of the tanks was acceptable, except for the potential issue discussed below.

The inspectors reviewed information to corroborate overall AMP intent. The inspectors reviewed the proposed procedure for the CST inspection. Aside from some minor problems discussed elsewhere in this report with similar proposed procedures (e.g., RHR HX inspection procedure and treated water systems piping inspection) the inspectors found the proposed procedures acceptable. The inspectors knew of material loss problems in aluminum tanks at other plants that may make this inspection procedure important to the applicant. The Hatch plant has an aluminum Unit 1 CST. The inspector asked the applicant if the tank had electrical isolation between the tank and the connecting piping systems. The isolation would prevent tank material loss due to a galvanic potential differential. The applicant did not immediately know of any details on the electrical isolation kits nor did they have a PM task to check the insulators. The applicant initiated an engineering work request (RER 2001-48) to investigate this potential problem after the inspectors left the site. The type of potential problem should naturally fall under the applicant's new AMP for galvanic corrosion discussed elsewhere in this report.

In summary, the new AMP for the tanks was acceptable to the inspectors. The applicant was looking into program improvement considerations and a potential issue with CST electrical isolation at the end of the inspection.

11. Flow Accelerated Corrosion (FAC) Program

FAC is the accelerated loss of wall thickness in carbon steel piping caused by two phase water flow conditions and susceptible piping configurations. The FAC Program, an enhanced program, is credited in the LRA as an aging management program for portions of the following systems:

B21 - Nuclear Boiler
E41 - HPCI
E51 - RCIC
N61 - Main Condenser

The program is credited for managing the loss of material in carbon steel piping and components and consists of monitoring the wall thickness of susceptible carbon steel piping and components in various systems, and replacing affected piping prior to failure. In many cases, FAC resistant materials are used for replacements. The program is based on EPRI NSAC-202L, Recommendations for an Effective Flow-Accelerated Corrosion Program. The program models susceptible systems and predicts piping wall wear rates. The model is supplemented and updated with periodic thickness inspections of selected components each cycle. Based on the model and inspection results, decisions are made on pipe replacement schedules.

The FAC Program is controlled by the Hatch Nuclear Plant Flow-Accelerated Corrosion Program and Southern Nuclear Plant E. I. Hatch Inspection and Test Procedure 42IT-N36-001-0S, Inspection of Plant Steam Piping For Flow Accelerated Corrosion.

In addition to review and discussion of the program with responsible applicant personnel, the inspectors reviewed completed records and observed in-process FAC activities as follows to verify that the program was in place and being implemented:

During the Unit 1 Cycle 19 outage, FAC thickness inspections for components 1-8E-12, 1-7HD-14, and 1-5HD-14 in the extraction steam and heater drain systems were observed.

During the Unit 2 Cycle 15 outage, FAC activities were observed for five components. (see NRC Inspection Report 50-366/00-02, Section M1.2, for documentation of these inspection activities)

The inspectors reviewed inspection plans for the current outage, Unit 1 RFO 19 Preliminary FAC Inspection List, and also for a future outage, Unit 2 RFO 16 Preliminary FAC Inspection List. The inspectors reviewed the following inspection reports which document the results of FAC inspections:

E. I. Hatch Nuclear Plant - Unit 1 Flow Accelerated Corrosion End-of-Outage Summary Report dated December 5, 2000

E. I. Hatch Nuclear Plant - Unit 2 Flow Accelerated Corrosion End-of-Outage Summary Report dated April 26, 2000

The activities and records were found to be acceptable.

Based on the review of the LRA and discussions with responsible applicant personnel, the inspectors learned that the FAC Program will be enhanced to include some of the license renewal in-scope components that do not meet all of the traditional industry criteria for including in the FAC Program. Specifically, the turbine exhaust piping for the HPCI and RCIC systems will be included. The applicant provided the inspectors a proposed revision to Procedure 42IT-N36-001-0S, which includes these components. The proposed revision states that the enhancements will be implemented by August 6, 2014 for Unit 1 and June 13, 2018 for Unit 2.

Although piping 2" diameter and smaller is not modeled, this piping is included in the FAC program. The applicant's practice is to replace small diameter susceptible piping (based on operating experience and engineering judgement) with materials resistant to FAC rather than periodically inspect. The applicant provided evidence that this practice is being used and a large quantity of piping has been replaced. However, the inspectors noted that the FAC program and proposed enhanced procedure do not describe clearly the details of this practice. The applicant agreed and stated that the practice will be more clearly defined in the proposed procedure.

In review of the LRA the inspectors noted errors in Section 3.2.1. Specifically, Table 3.2.1-2 listed the FAC Program as an aging management program for main steam flow nozzles. FAC is not an aging mechanism for high quality steam components. In addition, Section 3.2 six column tables list FAC as an aging management program for loss of material in valve bodies. Valve bodies are not modeled or included in the FAC Program. The applicant stated that they were aware of other problems in the six column tables and the tables would be reviewed for errors and corrected.

12. Suppression Pool Chemistry Control

The purpose of this chemistry AMP is to mitigate carbon steel and stainless material loss in the Torus. The chemistry control focuses upon minimizing the detrimental ionic species and conductivity. As discussed above in section II.B.9 on the Torus inspection AMP, desludging of the water in the pool helps chemistry control efforts. Per an inspector review, the existing chemistry control program values match the guidance values found in the EPRI TR-103515 document. Based on vendor inspection reports such as S.G. Pinney Report NUC0990102 for the Unit 1 Torus, dated July 19, 1999, the Torus has been maintained in working order. The inspectors also reviewed video tapes of the internal inspection of the Torus that revealed the surface conditions were acceptable and corroborated the report's conclusions. The inspectors found this AMP acceptable.

13. Equipment and Piping Insulation Monitoring Program

Insulation provides protection and thermal efficiency for the in scope equipment and piping. The AMP was enhanced to add other inspection requirements. The scoping of piping insulation was discussed in section C.a.11 of NRC Inspection Report 50-321, 366/00-009. During the scoping review, the inspectors examined the existing site procedures and drawings. The applicant has modified two of the site procedures (52GM-MNT-019-0S, Removal, Storage, and Installation of Thermal Insulation, Revision 2 ED 2, and 52GM-MNT-018-0S, Removal, Storage, and Installation of Reflective Insulation, Revision 3 ED 2) to add the LRA Appendix B insulation inspection frequency requirements. Additionally the inspectors reviewed a change to the cold weather checks procedure (52PM-MEL-005-0S, Cold Weather Checks, Revision 9 ED 3) indicating that the AMP scope added the yearly inspection frequency. The inspectors reviewed the changes and found the procedures and the inspection cycle acceptable. During outage walkdown inspections and plant tours, the inspectors found the majority of insulation appeared to be intact and in good condition.

In one SW valve pit, the inspector observed that the insulation covering safety-related piping and components had been walked on and partially crushed. This insulation was old and weathered. This was pointed out to the applicant. The applicant's main administrative maintenance procedure (50AC-MNT-001-0S, Maintenance Program, Revision 30) which is relied upon by the AMP as a program upper tier document, directed personnel not to walk or step on insulation. The maintenance procedure does not recognize the insulation removal and replacement procedures indicated above for entry and egress from work involving insulation. Linking these procedures could be a potential improvement in the AMP. The inspectors found the overall AMP activities acceptable.

14. Torque Activities

The Torque Activities program is described generally in Appendix B, Section B.1.11 of the LRA. This program applies to bolts, studs, nuts, and washers within systems in scope of license renewal. The applicant plans to utilize an existing program, with only minor changes, described in procedure 51GM-MNT-033-0S, Torquing Procedure, Revision 6. This procedure appropriately covers torque technique, control of preload, use of hardened steel washers, use of belleville washers, leveling passes, lubrication, and calibration as described in the LRA to minimize the potential for mechanical joint leakage.

The inspectors reviewed the applicable procedure and applicant proposed changes. In addition, the inspectors discussed this program's attributes and operating experience history with the responsible personnel. The five year history had not shown any loss of function due to mechanical joint leakage. The inspectors concluded that torquing activities were controlled adequately to meet the applicants LRA commitments.

15. Galvanic Susceptibility Inspections

The Galvanic Susceptibility Inspections program is described generally in Appendix B, Section B.3.1 of the LRA. The program is intended to provide for one time inspections to provide objective evidence that galvanic activity is being managed adequately. The applicant plans to perform a sample inspection of carbon to stainless steel connections in the PSW and RHRSW systems since these are believed to be the most susceptible areas and determine the need for further inspections based on these results. Planned inspections include visual, radiographic, and ultrasonic examinations. This will be a new program. The applicant has developed a proposed procedure, Galvanic Susceptibility Inspection.

The inspectors reviewed the proposed procedure and held discussions regarding program attributes with responsible personnel. The inspectors noted that the scope defined in Appendix B did not list system E21, Core Spray System as credited in Table 3.2.3-3 of the LRA. The applicant indicated that this would be corrected. In addition, the inspectors noted that the proposed procedure could be enhanced in two areas. The first area was the need to define qualifications for visual examiners. The second involved the fact that examination acceptance criteria was not yet well defined. For example, the proposed criteria required determination of significance by the examiner judgement versus specific criteria. The applicant indicated that the procedure would be enhanced in these areas. The inspectors expressed their view to the applicant that the aluminum condensate storage tank on Unit 1 would be a logical sample item for this program due to the potential issue of material loss discussed in section II.B.10.

16. Closed Cooling Water Chemistry Control

This AMP controls the chemistry in two systems via existing programs and procedures. Only portions of the systems involved are within scope. They are the portion involved with containment integrity. The AMP monitored certain chemistry compounds and managed bactericides that suppress growth in these systems. The procedures in the AMP were reviewed and found to meet the EPRI guidelines of TR-107396. As with other chemistry AMPs, the program is preventive and has no direct way to measure aging effects.

The inspectors sampled available information to corroborate the AMP had been effective. The inspectors looked at coupon test data from the Reactor Building Closed Cooling Water (RBCCW) system finding that the coupon material removal rate was conservatively less than the guidance values. The inspectors reviewed the tube plugging records on the RBCCW heat exchangers finding that the there was margin on tubes needed for cooling and the numbers of existing plugged tubes were not close to the HX plug limits. The inspectors reviewed the Drywell isolation valve local leak rate stroke data on the RBCCW valves finding that the valves had very few problems in the past and none of which related to chemistry problems. The information examined indicated that the chemistry AMP had been functioning well to support plant operation.

17. Treated Water Systems Piping Inspections

The Treated Water Systems Piping Inspections program is described generally in Appendix B, Section B.3.2 of the LRA. The program is intended to be a one time examination to confirm that existing chemistry control program is managing aging in piping that is not examined under another program. The applicant plans to sample at least 25 areas for inspection based on susceptibility, evaluate findings, and conduct further reviews as necessary. Planned inspections include visual, radiographic, and ultrasonic examinations. This will be a new program. The applicant has developed a proposed procedure, Treated Water Systems Piping Inspection.

The inspectors reviewed the proposed procedure and held discussions regarding program attributes with responsible personnel. The inspectors noted that the scope defined in Appendix B did not list system E11, Residual Heat Removal as credited in Table 3.2.3-2 of the LRA. The applicant indicated that this would be corrected. In addition, the inspectors noted that the proposed procedure could be enhanced in three areas. The first area was the need to define qualifications for visual examiners. The second involved the fact that the scope did not include some systems which were identified in the LRA for this program. The third involved the fact that, although general guidance was included, the process for selection of the samples was not yet well defined. The applicant indicated that the procedure would be enhanced in these areas.

18. Diesel Fuel Oil Testing

The applicant described its diesel fuel oil testing program in Sections A.1.3, B.1.3, C.2.2.7.1, and C.2.2.7.2 of the LRA. The diesel fuel oil testing program applies to the emergency diesel generator fuel oil storage tanks, fuel oil day tanks, and the associated transfer piping and components. It also covers the fire pump diesel fuel oil storage tanks and the associated piping and other components in the fire protection system included in the LRA scope. The diesel fuel oil testing program consists of quarterly checking diesel fuel oil storage and day tanks in the emergency and fire pump diesel generators for the presence of water, verifying that the total particulate concentration is within acceptable limits, removing any accumulated water, also sampling new fuel oil before off loading from the delivery vehicle, and introducing an additive which minimizes growth of microorganisms which could induce Micro biologically Induced Corrosion.

The Inspectors reviewed procedure 60AC-HPX-010-OS Rev. 9 ED 3 “Chemistry Program” effective 10/17/00. This is a general procedure for all plant chemistry control and addresses Diesel Fuel Oil but contains few specifics. The inspectors reviewed procedure 64CH-SAM-002-OS Rev.8, ED 2, Diesel Fuel Oil: Sampling and Analysis effective 2/24/00. The inspectors discussed this program with applicant engineers who perform the sampling and reviewed the results of quarterly sampling for the year 2000 to date along with test results of fuel oil being received on site. Test data shows that sampling has been performed as required. Data shows that there have been recurring instances of Total Particulate samples exceeding the acceptance criteria of 10 milligrams per liter for unknown reasons. When this happens, plant maintenance personnel employ procedure 52PM-R43-007-OS Rev 3 ED 1 “Diesel Fuel Oil Storage Tank Cleaning effective 3/22/00 which recirculates the fuel oil through filters until sample results come back within Total Particulate acceptance criteria. This procedure also contains instructions for draining and manually cleaning the fuel oil tanks if necessary. The inspectors’ review of past sample data confirmed that the Diesel Fuel Oil Testing program is currently being implemented.

In the fall 2000 outage one of the five buried diesel fuel oil tanks was drained and cleaned. The inspector reviewed a documented report of that work, with photographs. While the tank was drained the applicant took a series of 144 UT measurements of the tank bottom wall thickness. The tank is a nominal 0.5 inch thick plate steel and no point measured less than 0.500 inches or more than 0.524 inches. Therefore the report concluded, there has been no significant wall deterioration of the emergency diesel generator fuel oil storage tanks.

III. Electrical Component Aging Management

1. Wetted Cable Activities

In Sections A.1.16 and B.1.16 of the LRA, the applicant described an existing aging management program, wetted cables activities, that provides for mitigating activities as well as condition monitoring activities associated with cables exposed to a wetted environment. Several 4kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings. These in scope cables are prevented from remaining immersed in rain water for long periods of time by periodically removing standing water from the pull boxes. The affected systems include RHR, RHRSW, Core Spray, and PSW.

The inspectors reviewed existing plant procedure 52PM-Y46-001-ON, Rev. 5 ED 2 “Inground Pullbox and Cable Duct Inspection For Water”, effective 7/20/00. The inspectors also reviewed a proposed revision of the same procedure which had been revised to include the commitments of the LRA. The proposed procedure highlighted certain pull boxes to designate that they contain 4kV cables subject to aging management and required that those pull boxes be emptied every quarter. The procedure states that the remaining boxes need only be checked and drained as required. However, the inspectors spoke with maintenance personnel who perform this work and learned that their actual practice is to empty all pull boxes once per quarter.

The inspectors noted that the proposed procedure included two additional pull boxes in a table on page 11 which were not included in the existing procedure. The inspectors discussed the reason with applicant representatives who stated that while preparing the proposed procedure, they had recognized there were two additional in-scope pull boxes which were not listed in the existing procedure. The inspectors expressed the view that the existing procedure should be revised soon to list the two additional pull boxes and to mark them on the enclosed yard maps so those pull boxes can be included in the program at the next performance of the existing procedure.

The inspectors reviewed a second existing procedure 52IT-MEL-003-OS, Rev.8 ED 1 “High Potential and Megger Testing of Electrical Equipment and Cables” effective 5/19/00 related to this AMP, and also a proposed revision to that same procedure. The procedure provides directions for performing Direct Current High Potential (HIPOT), Megger and polarization index testing of plant electrical equipment. When new terminations are made, the cables are HIPOT tested to provide additional assurance that the cable insulation integrity is sound. In addition, Megger testing is performed on in-scope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks. Cables and loads must successfully pass Megger and polarization index testing.

The proposed procedure did not yet contain the frequency requirements specified in section B.1.16 “Wetted Cable Activities” of Appendix B to the LRA. That section states that RHR, RHRSW, and Core Spray motors and cables will be Megger tested every 18 months and PSW motors and cables will be Megger tested every 12 months. Applicant representatives stated that not all the newer commitments in Appendix B are yet in the proposed procedures and those testing frequency requirements would be added to the proposed procedure before it is approved. The inspectors concluded that this existing aging management program is functioning and when enhanced with the proposed procedures, it is capable of helping to manage the aging of 4kV in-scope electric cables.

2. Insulated Cables and Connections Aging Management Program

In a letter dated January 31, 2001, in response to NRC questions, the applicant described their proposed Insulated Cables and Connections aging management program as a condition monitoring program designed to confirm that age-related degradation is not inhibiting component function of insulated cables and connections within the scope of license renewal during the period of extended operation. The applicant stated that program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the primary containment structure, reactor building, radwaste building, diesel generator building, turbine building, control building, intake structure, and main stack, which could be subject to aging effects from heat or radiation. This program does not include cables and connections that are in the 10 CFR 50.49 Environmental Qualification program as aging of EQ equipment is managed by the EQ program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment.

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect.

The applicant stated that change in material properties of the conductor insulation is the applicable aging effect and changes in material properties managed by this program are those caused by severe heat or radiation (conditions that establish an adverse, localized environment). Accessible insulated cables and connections installed in adverse, localized environments will be inspected at least once every 10 years. Inaccessible cables and connections will be tested at least once every 10 years. The specific type of test performed will be determined prior to each test. Samples may be used for this program and if used, an appropriate sample size will be determined prior to the inspection or test.

The applicant committed that following issuance of a renewed operating license for Plant Hatch, the initial inspections and tests will be completed by the end of the initial license term for each Unit (August 6, 2014 for Unit 1 and June 13, 2018 for Unit 2). The inspectors discussed the program with applicant representatives. Because this is a new AMP yet to be developed, there were no proposed procedures or other documents for the inspectors to review. Therefore the inspectors could reach no conclusion as to the acceptability of AMP implementation.

IV. Review of Civil/Structural Aging Management Programs

The inspectors examined various documents describing existing and planned inspection programs for civil engineering structures and components, which addressed aging management for license renewal. The following programs were examined by reviewing existing procedures, reviewing past inspection data if available, and discussing the programs with responsible applicant engineers:

1. Protective Coatings Program

The Protective Coatings Program is described generally in Appendix B, Section B.2.3 of the LRA. A current applicant program is described in procedure 42EN-ENG-025-0S, Protective Coatings Program, Revision 0. This program appropriately covers attributes such as proper preparation techniques, application techniques, material requirements, inspections, and personnel qualifications for Service Level (SL) I, II, and III coatings. This program provides a means to prevent or limit corrosion resulting from contact of base material with a corrosive environment. The current program provides for special inspections of SL I coatings. The applicant currently does not have in use coatings that meet the definition of SL III. The applicant plans to enhance the current program for license renewal and plans to issue a procedure to provide for a baseline inspection and followup inspections as necessary for SL II coatings. The licensee indicated that SL III requirements would be added if necessary at a later date. The applicant has developed a proposed procedure for baseline inspections; the Augmented Protective Coatings Surveillance Inspection. In addition, the applicant plans to provide for inspection of coated surfaces which are buried when these areas become available via excavation. An enhancement to procedure 45QC-MNT-001-0N, Excavation & Earthwork Quality Control, Revision 2 had been initiated for this purpose.

The inspectors reviewed applicable procedures, proposed enhancements, and the proposed new procedure; reviewed recent inspection results; held discussions with responsible personnel regarding program attributes and inspection results; and conducted walkdowns of various plant areas to observe for effects of corrosion.

Generally, the procedures provided for the appropriate attributes of a good coatings program and provided for the additional inspections committed to in the LRA. The inspectors noted that the scope defined in Appendix B did not list system T52, Drywell Penetrations as credited in Table 3.3.1-6 of the LRA. The applicant indicated that this would be corrected.

The inspectors noted that the existing procedure, 42EN-ENG-025-0S, was unclear regarding the definition of SL II coatings. Section 2.0 described SL II as non-safety-related, however, Attachment 1 stated that SL II "would logically include some that may not be classified as safety-related coatings, but that protect systems essential to plant operability and availability". The applicant indicated that this procedure would be clarified. In addition, the inspectors noted that the proposed procedure, Section 8.5 implied that when problems are identified a coatings specialist would independently determine operability. The applicant indicated that the procedure would be enhanced to assure consultation on equipment operability questions with the appropriate design/system engineer.

During the walkdown inspections, the inspectors noted a number of components which had varying degrees of corrosion and were not being maintained by the protective coatings program. These were described in section I.B.7 above. These included various supports in the intake structure associated with the PSW and RHRSW systems, and on the Diesel Building roof, Cardox fire suppression piping, valves, and bolting; and Diesel Generator silencers.

The inspectors also reviewed Engineering Service Procedure 42SV-L23-001-0S, Safety Related Protective Coatings Surveillance, Revision 0 ED1, 11-10-00. This procedure provides instructions for performing surveillance inspection of and monitoring of all coatings systems that have been classified as safety related including coatings applied to Drywell and Torus shell, concrete floors, structural steel, piping and other equipment located inside primary containment and reporting inspection results. This procedure also inspects the coatings on safety related service water systems and diesel generator combustion air intakes. Section 2.2 of the procedure states that the frequency to perform the surveillance is normally once per operating cycle. The inspectors found the procedure adequate.

The inspectors reviewed the most recent protective coatings surveillance visual inspection records. The inspection was performed on Unit 1 in October, 2000 and in March, 2000 for Unit 2. NRC inspectors observed portions of the visual inspection of Unit 1. Both the NRC inspectors and the Hatch inspectors reported that the Drywell is in good condition both inside and out. The general comments of the applicant inspectors indicates that "inspection revealed very little difference in coating condition from last outage. 2.5 sq. ft. of degraded qualified coating was identified. This condition does not affect plant operability." Condition report CR 00009394 and MWO 1-00-03500 were written to document this finding. CR 00002717 and MWO 2-00-0990 were written to document similar conditions on Unit 2 following inspections.

The applicant hired an outside contractor to perform visual inspection of the Torus interior. Underwater Engineering Services, Inc. performed the inspection for both Units. Unit 1 was inspected in July, 1999 and Unit 2 was done in December, 1998. Both inspections performed were to remove 100% of the sludge deposited from the Torus shell in all 16 Torus bays. Visual inspections were performed on submerged portions of all 16 Torus bays to identify any coating defects, structural deficiencies, or any other conditions that could have an adverse affect on plant operations. Inspection Report FER-NUC0990102, "Unit 1 Torus Desludge, Inspection & Coating Repair," July 14, 1999, indicated that inspection revealed 2423 areas of rust through of the zinc coatings. These areas of localized corrosion range in size from 1/8" to 2" in diameter and are located in every bay of the Torus. However, the report concludes that from the standpoint of the integrity of the Torus pressure boundary, the Hatch Unit 1 Torus pressure boundary immersion areas are in acceptable condition, as the total area of corrosion identified was far less than 1% of the total surface area, and those areas of localized corrosion that were identified exhibited little or no pitting. The inspection report for Unit 2, FER-NUC0980109, Underwater Desludging and Coating Inspection of the Torus Pressure Boundary, December 19, 1998, stated that approximately 118 areas of corrosion were identified on the pressure boundary. Individual corrosion areas are approximately 2 to 4 square inches in size. But the report concluded that the Hatch Unit 2 Torus pressure boundary immersion areas are in acceptable condition. The inspectors also viewed video tapes of the underwater inspections and found that there are rust spots but only on a small portion of the total Torus interior. The inspectors, therefore, agree with the applicant that the Torus protective coating current condition is adequate.

The inspectors conclude that the Hatch protective coatings program is capable of protecting structures, systems, and components from corrosion so the structures, systems, and components will be able to perform their intended function(s) during the extended period of operation.

2. Fuel Pool Chemistry Program

The fuel pool chemistry program is a mitigating activity designed to maintain structural integrity, reliability, and availability of the Plant Hatch spent fuel pools and contained components exposed to the spent fuel water environment. The principal elements of fuel pool chemistry control at Hatch are regular sampling, results analysis, and chemistry modification.

The fuel pool water chemistry is sampled and analyzed weekly to ensure the chemical contents are within the allowable values set by EPRI TR-103515, "BWR Water Chemistry Guidelines - 1996 Revision." When the chemistry contents of fuel pool water falls within the allowable, potential corrosion of structures and components exposed in a fuel pool water environment is minimized and the structures and components will be able to perform their intended functions. The applicant does not utilize structural monitoring to manage aging effects for the fuel storage system.

The EPRI guideline specifies the following limitations:

Conductivity	$\leq$ 2.0 μmho/cm
Total Organic Carbon (TOC)	$\leq$ 400 ppb
Chloride & Sulfate	$\leq$ 100 ppb

The FSAR for both Units contain limitations for pH (5.3 - 8.6) and Filterable solids ($\leq$ 100 ppb).

The inspectors reviewed Chemical Control Procedure 64CH-SAM-022-0S, Fuel Pool Cooling Cleanup System Sampling and Analysis, Revision 3 ED 3, October 6, 2000. This procedure provides instructions for sampling and analysis of the Fuel Pool Cooling and Cleanup System to ensure the proper orientation of the demineralizers. The procedure states in Section 2.1 that it is only applicable to systems G41 and G71. G41 is spent fuel pool cooling and cleanup and G71 is decay heat removal. It does not apply to system T24 (fuel storage). The applicant is relying on chemical control of the spent fuel pool cooling system to keep the fuel pool water chemistry within allowable. The inspectors consider that this procedure should also apply to system T24 and the applicant agreed to revise this procedure to address this concern.

The inspectors reviewed the sampling and analyzing records of both Units for the last six months (July - December, 2000) and found all results were within the specified limits. Based on the inspectors' review of the procedure 64CH-SAM-022-0S and the results of the sampling, the inspectors conclude that the fuel pool chemistry program is adequate to manage the fuel storage facilities at Hatch.

3. Primary Containment Leakage Rate Testing Program

This program is a condition and performance monitoring program that ensures the structural integrity of the primary containment through visual inspection and performance testing activities. This program applies to all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. This includes the steel primary containment, containment penetrations, and containment internal structures that perform a pressure retaining function.

Administration Control Document 40AC-ENG-021-0S, Primary Containment Leakage Rate Testing Program, Revision 0, March 19, 1996, is the controlling document for the implementation of the primary containment leakage rate testing as required by Section 5.5.12 of the Hatch Units 1 & 2 Technical Specifications (TS). The applicant's proposed revision of this document also provides guidance for the implementation of visual inspection and performance testing of the Hatch primary containment.

The inspectors reviewed Procedure 40AC-ENG-021-0S and found that it provides guidance for the primary containment leakage rate tests. Section 8 of this document provides the procedure for how to perform the tests including documentation of test results. Section 8.1.1 specifies that "Test frequencies shall be determined in accordance with 42N–INS-001-0S". The inspectors reviewed 42N-INS-001-0S and found that it does not contain this information. When the inspectors interviewed the responsible engineer, the engineer told the inspectors that the reference is a mistake. The actual reference should be 42N-INS-002-0S and the procedure reference error has existed for a long time. The applicant agreed to correct this error in the existing plant procedure.

The inspectors reviewed Procedure 42N-INS-002-0S, "Containment Leakage Rate Testing Plan," Revision 5, October 13, 2000, and found the needed information. Type A component test is performed every 9 years instead of the 10 years as specified in 10 CFR 50, Appendix J because of the 18 month refueling cycle. Types B and C tests are performed at each refueling cycle.

The inspectors reviewed the most recent Type A test results data of both Units, Unit 1 in May 1993 and Unit 2 in January 1996. The inspectors found that the procedure was followed and the results acceptable. The inspectors also reviewed the most recent test results of Types B and C tests. Unit 1 was perform during the last refueling outage in October 2000 and Unit 2 was done in March 2000. When a valve or other device exceeded their allowable leakage, condition reports were issued followed by a maintenance work order (MWO). Maintenance work was performed on the devices or they were replaced by a new device. Subsequent tests were performed to ensure that the device passed the leakage rate tests. The inspectors reviewed several CRs and MWOs to confirm their acceptability.

On one occasion, test No. 1-0107C-B1, performed on 10/30/00 for an expansion bellows of a main steam line, the test result exceeded the allowable (102 vs 21) and there was no indication of what happened after the test. The inspectors requested an explanation from the responsible engineer. The responsible engineer told the inspectors that the test number was 1-007C-B1 instead of 1-0107C-B1 and there was an engineering evaluation to show that the overall leakage rate was less than 0.6 La and, therefore, the test is acceptable. The inspectors reviewed document 42SV-TET-001-1S, "Local Leak Rate Test Data Sheet," issued 11/6/00 which stated that "Test value is above administrative limit but will not result in 0.6 La being exceeded. This test will be acceptable. Test frequency will not be extended. Test history indicates trend is acceptable". The inspectors agreed with this assessment.

The inspectors concluded that the applicant's leakage rate test program is being implemented adequately and the program provides an acceptable method to manage the aging effects of the primary containment. The applicant agreed to correct the one discrepancy on the referencing document and the incorrect documentation of a local leak rate test.

4. Structural Monitoring Program

The Structural Monitoring Program is described generally in Appendix B, Section B.2.5 of the LRA. The applicants plans to utilize the existing program described by procedure 40AC-ENG-020-0S, Maintenance Rule (10CFR50.65) Implementation and Compliance, Revision 3 and companion document A-44985, Structural Monitoring Program for the Maintenance Rule, Revision 4. This program contains all structures required by the LRA. Appropriate criteria has been established in accordance with industry guidance as well as inspection guidance and personnel qualifications.

The structural monitoring program is designed to fulfill the requirements of the maintenance rule. The Maintenance Rule encompasses only structures, systems, and components (SSCs) that directly affect plant operations, and is not entirely suitable for license renewal. The inspectors reviewed Procedure 42AC-ENG-020-0S and found that the procedure was written primarily for systems. Section 8.1, “Selection of Plant Structures, Systems, and Components” only listed systems and system functions. Section 8.6, “Performance Monitoring and Reporting” only mentioned system functions and trends. However, the applicant was in the process of enhancing the program. In its proposed revised version, the applicant added statements which are pertinent to structures. Proposed Section 8.9.1 stated that “The structural monitoring program provides assurance of the functionality of structures which are under the scope of the Maintenance Rule and the License Renewal Rule. It provides a means to satisfy the requirements of both Rules for structures and structural components.” Proposed Section 8.9.4 stated that “If the Southern Company Services (SCS) Hatch Project Structural Monitoring Program (SMP) Lead finds a deficient condition, he/she will notify the Structural Monitoring Coordinator (SMC), who will generate a condition report.”

The inspectors also reviewed document A-44985, Structural Monitoring Program for Maintenance Rule for Plant Hatch. It specifies that the program is “to provide a means to satisfy the Maintenance Rule requirements for structures and structural components”. The scope of the inspections including applicable structural components as listed in Section X of the document and the inspections are both baseline and periodic. The initial condition survey is comprised of baseline inspections which establish a reference in time for comparison to future inspections. The scope and frequency of the periodic inspection will be determined considering data obtained during previous inspections. Section IX deals with possible corrective actions. The resolution could be more rigorous inspection, re-analysis, NDE/NDT methods, design enhancements, and/or repair. Section X contains existing programs and structures under Maintenance Rule scope, examiner qualifications, etc. The inspectors considered the procedure adequate.

For structures and structural components located in inaccessible areas, the applicant indicates that the proposed revised Quality Control Procedure, 45QC-MNT-001-0N Excavation & Earthwork Quality Control, Revision 2, August 25, 2000 has provisions to address this situation. The inspectors reviewed the proposed revision copy of 45QC-MNT-001-0N and found that the procedure defines and establishes methods, standards, and documentation procedures used to ensure that excavation and earthwork quality control are performed in strict accordance with the latest approved plans, specifications, and drawings. The procedure applies to excavations at Hatch where excavation depths are greater than 2 feet from the original grade. Section 7.1.3 of the proposed revision copy states that “Upon excavation that exposes structures or structural components, notify Maintenance Rule Coordinator in Engineering Support to evaluate the structure for potential Maintenance Rule impact prior to backfill. The Maintenance Rule Coordinator will notify appropriate structural monitoring personnel to conduct inspections of the portion of structures exposed due to excavation.” Section 7.1.4 of the proposed revised procedure further states that “Structural monitoring personnel will inspect the exposed portion of the structures, and document the results in accordance with Structural Monitoring Program and 40AC-ENG-020-0S”. The inspectors were concerned that when excavations exposed piping or coated structural components, the protective coating personnel should be notified to perform an inspection of the exposed portion for coating integrity. The applicant agreed to revise the proposed procedure to address the inspectors’ concern.

The applicant provided the inspectors with the most recent periodic inspection reports of the structural monitoring program for both Units. They are “Structural Monitoring Report for the Unit 1 Fall 2000 Outage,” March 7, 2001, and “Structural Monitoring Report for the Unit 2 Spring 2000 Outage,” February 13, 2001. The areas cover by both inspections are the same including the RWCU, Drywell and Torus, the Condensate Bays, for each Unit, and the common Intake Structure for both Units. Both reports conclude that “All inspected areas are deemed ‘Acceptable - no further evaluation required’ except for minor repairs required for conduit and instrument supports in the valve pit of the Intake Structures. Other areas exhibit some small degree of active degradation but not of potential significant structural impact”. The inspectors reviewed the reports and photographs taken during the walkdown visual inspections and considers they are acceptable.

The applicant’s structural monitoring program, as of today, can detect aging effects if implemented properly because it monitors structural components as well as structures. With the proposed enhancements, the program will be able to manage aging effects for inaccessible areas as well as accessible areas. The inspectors considered the program adequate.

5. Gas Systems Component Inspection

This program is a new program. It will provide for condition monitoring via one time aging management activities designed to provide objective evidence that the aging effects predicted for systems with gases as internal environments are being adequately managed. The applicant provided the inspector a proposed version of the procedure. The proposed procedure is a special purpose procedure. It states, in its objective, that “This procedure outlines a methodology for conducting a limited, one time inspection of piping, fittings, and valves in gas bearing systems to meet commitments described in the updated FSAR. This proposed procedure applies to all piping, fittings, valves, and ductwork installed within gas bearing systems and HVAC systems which, additionally, are in the scope of license renewal.”

The inspectors reviewed the newly proposed version of the Gas Systems Component Inspection procedure and made the following comments:

> There were no qualification requirements specified for the visual inspector.
> It is not clear who would select the samples.
> It is not clear who would make decisions about the inspection results.
> Qualifications of walkdown personnel are not specified.

The applicant agreed to address those comments in the procedure. From the attributes listed in Section B.3.3 of Appendix B of the application, the inspectors consider that it could be an effective program after incorporating the inspectors’s comments. However, the inspectors could not conclude the draft procedure was acceptable due to a lack of specific information.

6. Passive Component Inspection Activities

The Passive Component Inspection Activities AMP is a new condition monitoring aging management activity designed to collect, report, and trend age-related data. This activity will verify the effectiveness of preventive or mitigative programs/activities credited for aging management. In addition to piping, this activity is intended to inspect the external and internal surfaces of other passive components within the scope of license renewal, such as ducting, valve bodies, and strainers which are exempt from ASME Section XI inspections.

This is a new program and there are no procedures yet developed. The only available information are the attributes and introduction presented in Appendices A and B of the application. Section A.3.5.2 of Appendix A specifies that " Southern Nuclear anticipates that baseline inspections will begin for selected components as those components are made accessible due to normal maintenance activities. The baseline inspections may be done at any time". Section B.3.5 of Appendix B states that "The PCIA will be a set of on-going condition monitoring inspections designed to confirm that age-related degradation is not inhibiting component function predominantly in gas-bearing in-scope systems and components". The inspectors considered that this is a good approach, with a baseline inspection followed by a series of on-going condition monitoring inspections of in-scope systems and components. The baseline inspection will document the as found condition and the condition monitoring inspections will detect any progression of existing aging effects.

Section B.3.5 of Appendix B also lists many systems. At least, a portion of the systems will be within the scope of the PCIA. Many of the systems are water or oil bearing systems, such as the PSW and the fuel oil systems. The inspectors commented that the phrase "predominantly in gas-bearing systems and components" may not be appropriate. The applicant agreed to reconsider the wording when developing the PCIA procedures.

Section B.3.5 of Appendix B also states that "The PCIA will also be used for aging management of buried piping and for gaskets associated with the Control Building HVAC system". The inspectors expressed concern with this statement as to how the applicant is going to manage the aging effects for buried piping when accessibility is a problem. The inspectors urged the applicant to make it clear how this will be done when the procedure is developed.

There was currently no procedure to review; only attributes in Appendix B of the application. The inspectors considered those to be good attributes however, the inspectors could not conclude the program was acceptable due to a lack of specific information.

V. Fire Protection Activities

The fire protection activities aging management program (described in Section A.2.1 of the LRA) is comprised of condition monitoring and performance monitoring activities. These activities provide assurance that a fire will not prevent the performance of necessary safe shutdown functions. The portion of the Plant Hatch fire protection activities credited for license renewal is that portion included in Appendix B of the Fire Hazards Analysis (FHA), which includes passive long-lived components in water and gaseous-based fire suppression systems. Also included are the fire pump diesel fuel oil supply system (tanks and piping) and various fire rated assemblies. Diesel fuel oil testing is discussed above in section II.B.18.

The inspectors reviewed Appendix A of the LRA to identify independently fire protection license renewal commitments and compared these to the commitments identified in the applicant's commitment matrix. The inspectors then reviewed the proposed implementing procedures identified in the matrix to confirm that the commitments have been properly incorporated into the proposed procedures. A list of the proposed procedures reviewed is provided in Appendix B of this report.

The inspectors found that, generally, the applicant had identified the commitments detailed in the description of the fire protection activities in Appendix A of the LRA. The commitments related from Appendix B of the FHA, however, were not specifically documented in the proposed implementation procedures. Instead, a general reference was made to the FHA. Also, nonmetallic components requiring aging management were not specifically identified in either the commitment matrix or the implementing procedures. Finally, inspection of water suppression system strainers (an enhancement to existing plant procedures) was not captured in the commitment matrix. In each case, the applicant agreed that the matrix and proposed procedures should be revised.

The inspectors toured the plant and inspected several components within the scope of the fire protection activities AMP. The inspectors generally found the components in good condition. The inspectors observed that the fuel lines from the outdoor diesel fuel storage tank to the diesel fire pumps were in poor condition. The lines had external corrosion, were in contact with several different types of metals, and metal impact guards had corroded away in several places. When this was pointed out to the applicant, three Condition Reports, 2001 002370, 2372, and 2374, were initiated to document the problems and correct them.

The inspectors also viewed a videotape of an inspection of the internals of the fire water tanks performed in 1999. The tanks' internals still had the original coating and had experienced coating degradation. As a result, the applicant wrote a condition report and plans to recoat the tanks in the near future.

In addition, the inspectors reviewed past applicant identified Condition Reports for selected components in the fire protection system to determine to what extent age-related degradation had previously occurred in the components and how the degradation was corrected.
The inspectors reviewed condition reports for several rolling, swinging, and sliding fire doors and did not find evidence of age-related degradation.

The inspectors concluded that the commitments documented in the fire protection activity AMP have generally been incorporated into the proposed plant implementation procedures. In addition, the applicant has to date adequately identified, documented, and corrected age-related degradation of fire protection components.

VI Overall Conclusions

With regard to the specific systems addressed, the Inspectors concluded that existing formalized programs are implemented to accomplish aging management. For existing programs to be formalized and expanded and new programs to be developed, the applicants plans are appropriate to accomplish future aging management on the selected systems.

II. Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to members of applicant management on March 16, 2001. Proprietary information was reviewed during this inspection and identified as such by the applicant to the inspectors but no proprietary information is included in this report. Applicant management offered no dissenting views.

Partial List of Persons Contacted

Applicant

R. Baker, Project Manager, License Renewal Services
J. Betsill, Assistant General Manager, Hatch Nuclear Plant
M. Crisler, Senior Engineer
J. Hammonds, Engineering Support Manager
J. Hornbuckle, Senior Engineer
W. Jennings, Senior Engineer
S. Kirk, Engineering Supervisor
W. Lunceford, License Renewal Services Engineer
J. Mulvehill, Senior Engineer
C. Pierce, Manager, License Renewal Services
D. Smith, Superintendent of Chemistry
D. Swann, Hatch ISI Lead, ITS, Southern Nuclear Operating Company
S. Tipps, Plant Hatch compliance Manager
P. Wells, General Manager - Hatch Nuclear Plant
D. Willyard, Senior Engineer, Plant Hatch Inservice Inspection
P. Wolfinger, Plant Hatch License Renewal Coordinator

Other applicant employees contacted during the inspection included engineers, chemistry and maintenance personnel, operators, regulatory compliance personnel, and administrative personnel.

NRC

C. Casto, Director, Division of Reactor Safety, NRC, RII
K. Clark, Public Affairs, NRC RII
J. Munday, Senior Resident Inspector, Plant Hatch

APPENDIX A

Hatch License Renewal Inspection
Systems & Aging Management Programs Selected for Inspection
From Hatch license Renewal Application
Section 3 and Appendix A

Left column lists plant systems selected for inspection

Right column lists corresponding programs credited with managing aging

System Number	System Name	Aging Management Program
B11	Reactor Assembly	Boiling Water Reactor Vessel Internals Program Reactor Pressure Vessel Monitoring Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program Inservice Inspection Program
B21	Nuclear Boiler System	Torque Activities Inservice Inspection Program Protective Coatings Program Reactor Water Chemistry Control Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspections Galvanic Susceptibility Inspections Flow accelerated Corrosion Demineralized Water and Condensate Storage Tank Suppression Pool Chemistry Control Torus Submerged Components Inspection Program Gas Systems Component Inspections Passive Components Inspection Activities
B31	Reactor Recirculation	Inservice Inspection Program Torque Activities Reactor Water Chemistry Program Component Cyclic or Transient Limit Program Treated Water Systems Piping Inspection
C11	Control Rod Drive	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections Torque Activities Protective Coatings Program Gas Systems Component Inspections Passive Component Inspection Activities

C41 Standby Liquid Control	Torque Activities Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Protective Coatings Program
E11 Residual Heat Removal (RHR)	Torque Activities Protective Coatings Program Suppression Pool Chemistry Control Treated Water Systems Piping Inspections RHR Heat Exchanger Augmented Inspection and Testing Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program Inservice Inspection Program Galvanic Susceptibility Inspections Gas Systems Component Inspections Passive Component Inspection Activities Plant Service Water and RHR Service Water Inspection Program Torus Submerged Components Inspection Program
E21 Core Spray System	Torque Activities Protective Coatings Program Suppression Pool Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections Torus Submerged Components Inspection Program
E41 High Pressure Coolant Injection (HPCI)	Torque Activities Protective Coatings Program Gas Systems Component Inspections Reactor Water Chemistry Control Galvanic Susceptibility Inspections Demineralized Water and Condensate Storage Tank Chemistry Control Flow Accelerated Corrosion Program Suppression Pool Chemistry Control Treated Water Systems Piping Inspections Torus Submerged Components Inspection Program Gas Systems Component Inspections Passive Component Inspection Activities
L35 Piping Specialties	Protective Coatings Program Structural Monitoring Program

L36 Insulation	Equipment and Piping Insulation Monitoring Program
P41 Plant Service Water	Torque Activities Protective Coatings Program Plant Service Water and RHR Service Water Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Structural Monitoring Program Galvanic Susceptibility Inspections
Reactor Building Closed Cooling Water (RBCCW)	Torque Activities Protective Coatings Program Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
P64 Primary Containment Chilled Water (Unit 2)	Torque Activities Protective Coatings Program Closed Cooling Water Chemistry Control Treated Water Systems Piping Inspections
Plant Wide Electrical Components	Wetted Cable Activities Insulated Cables and Connections Protective Coatings Program Structural Monitoring Program
R33 Conduits, Raceways & Trays	Protective Coatings Program Structural Monitoring Program
R43 Emergency Diesel Generators	Demineralized Water and Condensate Storage Tank Chemistry Control Galvanic Susceptibility Inspections Treated Water Systems Piping Inspections Gas Systems Component Inspections Passive Component Inspection Activities
T23 Primary Containment	Protective Coatings Program Inservice Inspection Program Suppression Pool Chemistry Control Demineralized Water and Condensate Storage Tank Chemistry Control Treated Water Systems Piping Inspections Passive Component Inspection Activities Gas Systems Component Inspections Primary Containment Leakage Rate Testing Program Structural Monitoring Program

	Component Cyclic or Transient Limit Program
L48 Access Doors	Structural Monitoring Program Protective Coatings Program
T24 Fuel Storage	Protective Coatings Program Structural Monitoring Program Fuel Pool Chemistry Program
T29 Reactor Building	Structural Monitoring Program Protective Coatings Program
T41 Reactor Building HVAC	Torque Activities Protective Coatings Program Gas Systems Component Inspections
T52 Drywell Penetrations	Protective Coatings Program Primary Containment Leakage Rate Testing Inservice Inspection Program
T54 Reactor Building Penetrations	Structural Monitoring Program Protective Coatings Program
W33 Traveling Water Screens/ Trash Rakes	Structural Monitoring Program Protective Coating Program Plant Service Water and RHR Service Water Inspection Program Plant Service Water and RHR Service Water Chemistry Control Program Galvanic Susceptibility Inspections
W35 Intake Structure	Structural Monitoring Program Protective Coating Program
Y39 EDG Building	Structural Monitoring Program Protective Coating Program
Z29 Control Building	Structural Monitoring Program Protective Coating Program
X43 Fire Protection	Torque Activities Protective Coatings Program Fire Protection Activities Diesel Fuel Oil Testing

APPENDIX B

NRC Inspection Procedures Used

IP 71002: License Renewal Inspection Procedure

Partial List of Documents Reviewed

Engineering Documents

ASME Code Case N-480, dated May 10,1990

Electric Power Research Institute BWR Guidelines - 2000 Revision: TR-107396, TR 112214, and TR-103515

Hatch Unit 1 - Evaluation of Minimum Wall Thickness File: TWR 00-950, dated January 19, 2000

Hatch Unit 2, “Fifth Periodic Reactor Containment Building Integrated Leak Rate Test,” January, 1996.

Hatch Unit 1, “Reactor Containment Building Integrated Leakage Rate Test - Fifth Periodic,” May, 1993.

RES ST 95010 Hatch, “Structural Monitoring Report for the Unit 1 Fall 2000 Outage,” March 7, 2001.

RES ST 95010 Hatch, “Structural Monitoring Report for the Unit 2 Spring 2000 Outage,” February 13, 2001.

Plant Drawings

Drawing - 10-502, HH5440, Rev. 3, Reactor Building Drywell Foundation Concrete Pour Sequence

Drawing - 10-502, HH5447, Rev. 5, Reactor Building Drywell Foundation Interior Concrete Pours

Drawing: RHR Service Water System Pressure Test Diagram, Rev.3, PT-21039

Drawing: Turbine Building Service Water System Pressure Test Diagram, Rev. 7, PT-21033

Drawing -Unit 1 RBCCW System P&ID H-16009, Rev. 45

Drawing -Unit 2 RBCCW System P&ID H-26055, Rev. 30

Procedures and Programs

Hatch Project-Support Procedure HNMS-WP-22, Nuclear Maintenance Support Conduct of Operations, Revision 6

Hatch Project-Support Procedure HNMS-WP-44, Procedure For Inservice Inspection and Testing, Revision 2

Surveillance Procedure 42SV-B11-002-1S, Revision 1, Reactor Material Irradiation Specimen Surveillance

SNC Inspection and Testing Services Procedure ITS 2-2, Inservice Inspection Plans, Revision 4

SNC Inspection and Testing Services Procedure ITS 2-1, ISI Program - Including Relief Requests, Revision 5

Hatch Nuclear Plant Flow-Accelerated Corrosion Program, Volume 1 - Revision 1 and Volume 2 - Revision 9

SNC Inspection and Test Procedure 42IT-N36-001-0S, Inspection of Plant Steam Piping For Flow Accelerated Corrosion, Revision 6

BWR Vessel and Internals Project Documents

BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines (BWRVIP-18) July 1996

BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (BWRVIP-41) October 1997

BWR Core Shroud Inspection and Flaw Evaluation Guidelines (BWRVIP-76) November 1999

BWR Shroud Support Inspections and Flaw Evaluation Guidelines (BWRVIP-38) September 1997

BWR Top Guide Inspection and Flaw Evaluation Guidelines (BWRVIP-26) December 1996

BWR Lower Plenum Inspection and Flaw Evaluation Guidelines (BWRVIP-47) December 1997

BWR Integrated Surveillance Program Plan (BWRVIP-78) December 1999

BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (BWRVIP - 74) September 1999

BWR Standby Liquid Control System/Core Plate DP Inspection and Flaw Evaluation Guidelines (BWRVIP - 27) April 1997

BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines (BWRVIP - 48) February 1998

Inservice Inspection Program, Third 10-Year Interval, E. I. Hatch Nuclear Plant Units 1 & 2, Revision 6

Inservice Inspection Program, Third Ten-Year Examination Plan, E. I. Hatch Nuclear Plant Unit 1, Revision 5

Inservice Inspection Program, Third Ten-Year Examination Plan, E. I. Hatch Nuclear Plant Unit 2, Revision 6

52IT-MEL-003-0S, Rev. 8 ED 1, High Potential and Megger Testing of Electrical Equipment and Cables

52PM-Y46-001-0N, Rev. 5 ED 2, Inground Pullbox and Cable Duct Inspection for Water

52PM-R43-007-0S, Rev. 3 ED 1, Diesel Fuel Oil Storage Tank Cleaning

64CH-SAM-002-0S, Rev 8 ED 2, Diesel Fuel Oil: Sampling and Analysis

40AC-ENG-013-0S, Rev. 3 ED 2, Plant Service Water and RHR Service Water Piping Inspection Program

42IT-TET-012-2S, Rev. 3, Plant Service Water and RHR Service Water Piping Inspection Procedure

52PM-R42-001-0S, Rev. 6 ED 1, Battery Charger Inspection/Cleaning

42SV-SUV-047-0S, Rev. 2, Tours Surface, Relief Valve Piping and Miscellaneous Supports Visual Inspection

64CH-SAM-025-0S, Rev. 3 ED 1, Reactor Coolant Sampling and Analysis

64CH-SAM-023-0S, Rev. 4 ED 2, Plant Startup Chemistry

52PM-E11-009-0S, Rev. 3 ED 1, RHR Heat Exchanger Preventive Maintenance

64CH-OPS-006-ON, Rev. 12 ED 2, Plant Service Water and Circulating Water Treatment Systems

34GO-OPS-024-1S, Rev. 9 ED 1, Equipment Rotation and Flushing of PSW and RHRSW Piping Deadlegs

60AC-HPX-010-OS, Rev. 9 ED 3, Chemistry Program

64CI-OCB-035-0N, Rev. 3, Hatch DR/4000 SpectroPhotometer

52PM-E11-009-0S, Rev. 3 ED 1, RHR Heat Exchanger Preventive Maintenance

42EN-ENG-033-1S, Rev. 0 ED 1, PSW Flow Model Confirmation Data Collection

52GM-MME-028-0S, Rev. 2, Coating of Underground Metallic Pipe

52PM-MME-006-0S, Rev. 6 ED 3, Intake Structure Pit Inspection/Diving

64CH-OPS-005-0N, Rev. 3 ED 2, Make Up Demineralizer

64CH-SAM-026-0S, Rev. 1 ED 2, Condensate Systems Sampling and Analysis

52GM-MNT-019-0S, Rev. 2 ED 2, Removal, Storage, and Installation of Thermal Insulation

52GM-MNT-018-0S, Rev. 3 ED 3, Removal, Storage, and Installation of Reflective Insulation

52PM-MEL-005-0S, Rev. 9 ED 3, Cold Weather Checks

50AC-MNT-001-0S, Revision 30, Maintenance Program

64CH-ADM-001-0S, Rev. 16, Chemistry Miscellaneous Tasks

SPGAI Procedure-10-1-Hatch-HPBH964801, Rev. 0, Underwater Coating Inspection

SPGAI Procedure-10-2-Hatch-HPBH964801, Rev. 0, Underwater Coating Inspection

64CH-SAM-004-0S, Rev. 9, General Chemistry Sampling

64CH-SAM-017-0S, Rev. 8, Closed Cooling Water Sampling and Analysis

40AC-ENG-008-OS, “Fire Protection Program”

42SV-FPX-021-OS, “Surveillance of Swinging Fire Doors”

42SV-FPX-032-OS, “Automatic Sliding Fire Door Surveillance”

42SV-FPX-013-OS, “Rolling Fire Door Surveillance”

42SV-FPX-016-1S, “Sprinkler System Surveillance” (Unit 1)

42SV-FPX-016-2S, “Sprinkler System Surveillance” (Unit 2)

42SV-FPX-042-OS, “Inspection of Fire Tanks”

42SV-FPX-004-OS, “Fire Pump Test”

42SV-FPX-015-OS, “System Flush - Fire Protection Water”

42SV-FPX-002-OS, “Low-Pressure CO_2 System Surveillance”

42SV-SUV-007-OS, “CO_2 Fire Suppression Equipment Inspection”

42SV-FPX-007-OS, “Cable Tray Surveillance - Kaowool Material”

64CH-SAM-022-0S,Rev 3 ED 3 “Fuel Pool Cooling and Cleanup System Sampling and Analysis,”, October 6, 2000.

40AC-ENG-020-0S, Rev 3 “Maintenance Rule Implementation and Compliance,”, October 16, 1997.
45QC-MNT-001-0N, Rev 2 “Excavation & Earthwork Quality Control,”, August 25, 2000.

Structural Monitoring Program for Maintenance Rule, A-44985 - Plant Hatch, Revision 4, November, 1998.
42EN-INS-002-0S, “Containment Leakage Rate Testing Plan,” Revision 5, October 13, 2000.

42EN-INS-001-0S, “Inservice Testing Program,” Revision 5 ED 2, November 6, 2000.

Administrative Control Procedure, “Primary Containment Leakage Rate Testing Program,” Revision 0, March 19, 1996.

42EN-ENG-025-0S, Rev 0 ED1 “Protective Coating Program”, November 16, 2000.

42SV-L23-001-0S, Rev 0 ED1 “Safety Related Protective Coating Surveillance Inspection”, November 10, 2000.

51GM-MNT-033-0S, Torquing Procedure, Rev 6

42SV-SUV-029-1S, Cumulative Fatigue Usage Factor Monitoring, Rev 5

42SV-SUV-029-2S, Cumulative Fatigue Usage Factor Monitoring, Rev 4

A-44985, Structural Monitoring Program for the Maintenance Rule, Rev 4

Proposed Procedures:

Augmented Protective Coatings Surveillance Inspection

Galvanic Susceptibility Inspection

Treated Water Systems Piping Inspection

Proposed Special Purpose Procedure, Gas Systems Components Inspection.

Plant Records

Inservice Inspection Outage Plan, Edwin I. Hatch Nuclear Plant Unit 2, 2000 Spring

Inservice Inspection Outage Plan, Edwin I. Hatch Nuclear Plant Unit 1, 2000 Fall

Inservice Inspection Examination Records Final Report, 2000 Spring Refueling Outage (2R15)

Inservice Inspection Final Report, Edwin I. Hatch Nuclear Plant Unit 1, 2000 Fall

FAC Inspection Plans:	Unit 2 RFO 16 Preliminary FAC Inspection List Unit 1 RFO 19 Preliminary FAC Inspection List
FAC Inspection Reports:	E. I. Hatch Nuclear Plant - Unit 1 Flow Accelerated Corrosion End-of-Outage Summary Report dated December 5, 2000

E. I. Hatch Nuclear Plant - Unit 2 Flow Accelerated Corrosion End-of-Outage Summary Report dated April 26, 2000

42EN-ENG-033-1S, Rev. 0 ED 1, PSW Flow Model Confirmation Data Collection [Data collected 9-23-99]

42EN-ENG-033-2S, Rev. 0 ED 1, PSW Flow Model Confirmation Data Collection [Data collected 7-19-00]

Procedure 42IT-TET-012-2S, Rev. 3, Plant Service Water and RHR Service Water Piping Inspection Procedure [Data collected 6-28-99]

Form HPX-0658, Rev 2. RBCCW Corrosion Rate [Coupon data Unit 1: 3-16-00, ferrous and brass, and, Unit 2: 2-22-01, ferrous and brass]

Chemistry Form HPX-0551, Rev. 6, Release Via Unplanned Routes:Isotopic [grab samples: 3rd and 4th Quarter 2000,and, 1st quarter 2001 Unit 1 RHR Flume]

42IT-TET-004-0S. Rev. 5, Operating Pressure Testing of Piping and Components [Data collected 11-3-99]

Maintenance Work Order (MWO) number 10001235, date 4/28/00, 1E11 RHR Heat Exchanger Condition Report

MWO 2000008811, date 10/08/00 Tubeside (RHRSW) of the Heat Exchanger is Contaminated

MWOs 1-93-1407, 1-94-4561, 1-96-1179, and 1-97-2665 Unit1 RBCCW penetration valves 1P42-F051andF052; 9-30-79 to 10-18-00

MWO 2-91-1566 Unit 2 RBCCW penetration valves 2P42-F051andF052; 3-28-80 to 9-13-98

FER-NUC0980109, “Underwater Desludging and Coating Inspection of the Torus Pressure Boundary,” Hatch Unit 2 December 19, 1998. (S. G. Pinney)

FER-NUC0990102, “Unit 1 Desludging , Inspection & Coating Repair,” July 14, 1999.

42SV-TET-001-1S, “Local Leak Rate Test Data Sheet,” November 6, 2000, for penetration #X7C main steam line bellows.

Rpt1RF19 for the Unit1 local leak rate test, October, 2000.

Rpt2RF15 for the Unit 2 local leak rate test, March, 2000.

List of Acronyms

AMP	Aging Management Program
ASME	Americam Society of Mechanical Engineers
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel Internals Project
CCTLP	Component Cyclic Or Transient Limit Program
CFUF	Cumulative Fatigue Usage Factor
CR	Condition Report
CRD	Control Rod Drive system
CS	Core Spray system
CST	Condensate Storage Tank
DWT	Demineralized Water Storage Tank
EPRI	Electric Power Research Institute
FAC	Flow Accelerated Corrosion
FHA	Fire Hazards Analysis
FW	Feedwater system
HPCI	High Pressure Coolant Injection system
HX	Heat Exchanger
ISI	Inservice Inspection
ISP	Integrated Surveillance Program
IST	Inservice Testing
kV	Kilovolt
LRA	License Renewal Application
MS	Main Steam system
MT	Magnetic Particle Inspection
MWO	Maintenance Work Order
NDE	Nondestructive Examination
PM	Preventive Maintenance
PSW	Plant Service Water system
PT	Liquid Penetrant Inspection
RCIC	Reactor Core Isolation Cooling system
RBCCW	Reactor Building Closed Cooling Water system
RFO	Refueling Outage
RHR	Residual Heat Removal system
RHRSW	RHR Service Water system
RPV	Reactor Pressure Vessel
RR	Reactor Recirculation system
RT	Radiographic inspection
RW	Reactor Water
SER	Safety Evaluation Report
SL	Service Level
SLC	Standby Liquid Control system
SNC	Southern Nuclear Company
SSC	Structures, Systems, and Components
TRM	Technical Requirements Manual
TS	Technical Specifications
UT	Ultrasonic Inspection
VT	Visual Inspection