Tennessee Valley Authority, Post Office Box 2000, Decatur, Alabama 35609-2000

November 16, 2005

10 CFR 54

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop: OWFN P1-35
Washington, D.C. 20555-0001

Gentlemen:

In the Matter of	)	Docket Nos. 50-259
Tennessee Valley Authority	)	50-260
		50-296

BROWNS FERRY NUCLEAR PLANT (BFN) - UNITS 1, 2, AND 3 - LICENSE RENEWAL APPLICATION (LRA) - SUPPLEMENTAL RESPONSES TO NRC REQUESTS (TAC NOS. MC1704, MC1705, AND MC1706)

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

As delineated below, the enclosures to this letter contain the specific NRC requests for supplemental responses and the corresponding TVA responses:

- Enclosure 1: Open item OI 2.4-3, Drywell Shell Corrosion
- Enclosure 2: Finalization of Program Elements for Proposed Unit 1 Periodic Inspection Program

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- Enclosure 3: Open Item OI 4.7.7, Stress Relaxation of Core Plate Hold-Down Bolts
- Enclosure 4: Open Item from AMP Inspection On Inspection of Residual Heat Removal Service Water (RHRSW) Piping
- Enclosure 5: Operating Experience for Unit 1 in Satisfying the Intent of the License Renewal Rule
- Enclosure 6: Input for Layup Section of the SER
- Enclosure 7: Clarification of One-Time Inspection Program Versus Unit 1 Periodic Inspection Program

Additionally, Enclosure 8 corrects a non-technical error contained in TVA's January 31, 2005, letter to the NRC (Reactor Vessel and Internals Mechanical Systems Sections 3.1, 4.2, and B.2.1 - Response To NRC Request For Additional Information).

A summary of the commitments contained in this letter is provided in Enclosure 9. If you have any questions regarding this information, please contact Ken Brune, Browns Ferry License Renewal Project Manager, at (423) 751-8421.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 16th day of November, 2005.

Sincerely,

William D. Crouch
Manager of Licensing
and Industry Affairs

Enclosures:
cc: See page 3

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ENCLOSURE 1

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING
OPEN ITEM OI 2.4-3, DRYWELL SHELL CORROSION

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING OPEN ITEM OI 2.4-3, DRYWELL SHELL CORROSION

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning Open item OI 2.4-3, Drywell Shell Corrosion.

NRC Request

1. Open Item, OI 2.4-3, Drywell Shell Corrosion - This topic needs additional discussion between the staff and the Tennessee Valley Authority (TVA) to resolve items related to aging management of Drywell liner plates.

OI-2.4-3: (Section 2.4 - Drywell Shell Corrosion)

Supplement 1 of Information Notice (IN) 86-99 indicates that, if leakage from the flooded reactor cavity is not monitored and managed, there is a potential for corrosion of the cylindrical portion of drywell shell. As this corrosion would initiate in the non-inspectible areas of the drywell, it cannot be monitored by IWE inspections. Moreover, this degradation of drywell shell can occur even if there is very little water found in the sand-pocket area of the drywell. Thus, the reactor building to drywell refueling seal becomes a non-safety-related (NSR) item that can affect the integrity of the drywell shell (which is a pressure boundary component) during the period of extended operation, and falls under the requirement of 10 CFR 54.4(a)(2). For two BWR plants, the staff accepted an alternative to managing the aging of the seal. The alternative is to periodically perform ultrasonic testing (UT) of the cylindrical portion of the drywell shell

with an acceptable sampling program, as part of containment inservice inspection (ISI) program. After reviewing the response to RAI 3.5-4 (in the applicant's letter dated January 31, 2005) related to the operating experience of drywell shell corrosion at all three units, the staff came to the conclusion that the applicant should manage the aging (leakage) of refueling seals. The applicant is being requested to include the refueling seals within the scope of license renewal.

The applicant responded to Open Items 2.4-3 by letter dated May 31, 2005 (ADAMS Accession No. ML051520084). BFN does not include the refueling seals at the top of the drywell in the scope of license renewal and provides the following technical basis for that conclusion: The drywell-to-reactor building refueling seal and the reactor pressure vessel (RPV)-to-drywell refueling seal, in conjunction with the refueling bulkhead, provide a watertight barrier to permit flooding above the RPV flange while preventing water from entering the drywell. Providing a watertight barrier to permit flooding above the RPV flange in support of refueling operations is an NSR function. 10 CFR 54.4(a) sets forth the criteria that determine whether plant systems, structures, and components are within the scope of license renewal. The refueling seals do not satisfy any of the requirements set forth in 10 CFR 54.4(a)(1). The refueling seals are NSR and they are not relied upon to remain functional during design basis events. Thus, the refueling seals are not brought within the scope of license renewal by 10 CFR 54.4(a)(1). This issue remains open as of the date of this SER.

<u>TVA's response to Open Item 2.4-3:</u>

To provide the Staff with the necessary assurance that the potential degradation of the uninspectable side of the drywell is being monitored and managed:

For Unit 1, TVA will perform one time confirmatory ultrasonic thickness measurements on the vertical cylindrical area immediately below the drywell flange. This area is exposed to standing water and repeated wetting and drying during refueling operations. These ultrasonic thickness measurements will be obtained on the entire vertical portion of the liner accessible from inside drywell above elevation 637.0′ (Az 0° - Az 360°) with measurements taken at intersection points of approximately one foot grids. These ultrasonic thickness measurements will be obtained prior to restart of the unit. Similar inspections have been performed on Units 2 and 3 in this area as documented in BFN plant

procedure 0-TI-376, Appendix 9.7. A discussion of the previous inspections for BFN Units 2 and 3 is contained in TVA's response to Follow-up RAI 3.5-4, page E-13 in the letter from TVA to the NRC dated May 31, 2005 (ADAMS Accession No. ML05150084).

For Units 2 and 3, TVA will perform one time confirmatory ultrasonic thickness measurements on a portion of the cylindrical section of the drywell in a region where the liner plate is 0.75 inches thick. These ultrasonic thickness measurements will be obtained at four locations in close proximity to the platforms, approximately 90º apart, in an area at least three feet by three feet with measurements taken at intersection points of approximately one foot grids. This will provide a bounding condition since the nominal thickness of the wall in this region has the least margin. These ultrasonic thickness measurements will be obtained on Unit 2 and Unit 3 prior to their period of extended operation to provide added assurance that the integrity of the drywell shell is not being compromised by wastage before entering into the renewed licensing period.

Data from the ultrasonic thickness measurements described above will be reviewed by Engineering. If any areas of concern or non-conforming conditions are identified, a problem evaluation report (PER) will be initiated in accordance with the site Corrective Action Program, SPP-3.1. A corrective action plan will be developed in accordance with SPP-3.1 and an extent of condition and applicability to the other BFN units would be considered in the disposition of the PER.

ENCLOSURE 2

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING
FINALIZATION OF PROGRAM ELEMENTS FOR PROPOSED
UNIT 1 PERIODIC INSPECTION PROGRAM

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING FINALIZATION OF PROGRAM ELEMENTS FOR PROPOSED UNIT 1 PERIODIC INSPECTION PROGRAM

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning the Finalization of Program Elements for Proposed Unit 1 Periodic Inspection Program.

NRC Request

2. Program description for the proposed Unit 1 Periodic Inspection Program (B.2.1.42) - The program description provided by TVA for this new and plant specific program needs finalization of program elements as recommended by ACRS.

   A. Intended scope.

   B. Detection of aging affects: Criteria for identification of susceptible location

   C. Monitoring and trending: Frequency: such as prior to restart, before entering ,license renewal duration PEO, and after

   D. Acceptance Criteria: Corrective Action: Determination of action to be taken if or not degradation has been identified)

   E. Operating Experience: Lessons learned from Unit 2 and/or Unit 3

TVA Response

In a letter dated August 4, 2005, TVA responded to an NRC informal request of July 22, 2005, and provided a description of the Unit 1 Periodic Inspection Program and UFSAR program description equivalent to the program descriptions provided in Appendix A and B of the License Renewal Application for the other aging management programs.

A September 2, 2005 informal request provided eight questions on the proposed Unit 1 Periodic Inspection Program and UFSAR description provided in the August 4, 2005 TVA response. The following provides TVA's response to each question and revised versions of the proposed Unit 1 Periodic Inspection Program and UFSAR program description (equivalent to Appendix A and B of the License Renewal Application).

NRC Question 1

The statements in parentheses appear to include portions of the SRP-LR Appendix A.1.2.3, but not all of the specified information is presented. The applicant should review the entire Appendix A.1.2.3 and include additional applicable information. For example, items 3, 4 and 5 in SRP-LR Section A.1.2.3.4 identify information that should be included in the program.

TVA Response to Question 1

The words provided in quotes in the Unit 1 Periodic Inspection Program descriptions are the essential portions of the ten element descriptions provided in NUREG-1800, Appendix A.1.2.3. These descriptions are not a part of the BFN Unit 1 Periodic Inspection Program, but, are provided as clarification of what information is expected in the plant's program description. While the abbreviated versions appear sufficient to summarize the NRC expectations for each element, the full version of the NUREG-1800, Appendix A.1.2.3 description is included in the revised version of the Unit 1 Periodic Inspection Program (Attachment 2 of this enclosure).

NRC Question 2

The description of the program indicates that if failures are identified, the sample size will be appropriately expanded using the guidance of EPRI 107514. The term "failures" is not appropriate for license renewal. The applicant is requested to clarify if the term "degradation" rather than "failures" is the correct terminology.

TVA Response to Question 2

The reference to "failures" has been revised to "unacceptable degradation" in the revised versions of the UFSAR description of the Unit 1 Periodic Inspection Program and the Unit 1 Periodic Inspection Program (Attachments 1 and 2 of this enclosure, respectively).

NRC Question 3

For Element 1, Scope, the specific components to be inspected are to be identified within the AMP or a commitment to identify the specific selected scope at a later date is required. This information or commitment is required, since the AMR tables for specific system components do not identify the periodic inspection program being credited. For example, EPRI TR-107514 identifies specific components to be included in the sample for each system inspected at Calvert Cliffs.

TVA Response to Question 3

The use of EPRI 107514, "Age-Related Degradation Inspection Method and Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application," in the description of the Unit 1 Periodic Inspection Program has been deleted. The intent of the reference was to refer to the statistical sampling methodology presented in Chapter 4 of EPRI 107514, not the entire report.

The Unit 1 Periodic Inspection Program provides periodic monitoring of the non-replaced piping/fittings that were not in service supporting operation of Units 2 and 3, as described in Response to Follow-Up to RAI 3.0-9 contained in the TVA Letter to the U.S. Nuclear Regulatory Commission, Document Control Desk, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Lay-up Program (TAC Nos. MC1704, MC1705, and MC1706)" dated May 18, 2005.

The specific components included in the May 18, 2005 letter includes piping and welds in RHRSW (A&C loops in the tunnels), Fire Protection, EECW, RCW, CRD, CS, Feedwater, HPCI, Main Steam, RCIC, RHR, and RBCCW. The description of the specific components and systems has been expanded in the revised version of the Unit 1 Periodic Inspection Program (Attachment 2 of this enclosure).

NRC Question 4

The applicant identifies EPRI 107514 as a basis for determining the sample size. This document is applicable to Calvert Cliffs and was proposed for North Anna and Surry, but was subsequently withdrawn for North Anna/Surry at the request of the NRC reviewer, because it was not NRC reviewed or approved. This document has also been proposed for use on Nine Mile Point. EPRI 107514 uses the statistical approach for selecting an initial sample size on the basis of providing a 90% confidence level that 90% of a given population is not experiencing degradation. This report identifies that the 90/90 approach is based on a CCNPP internal memorandum and a sample size of 25 is appropriate for a any given population size. This report also identifies that a sample size of 75 would be required for a 95/95 confidence level. The basic intent of selecting a given sample size is to provide reasonable assurance that degradation is not occurring. Although there is not necessarily a quantitative regulatory basis for establishing a sample population used in aging management, other recent regulatory documents such as NUREG-1475, SECY 05-0052 and Regulatory Guide 1.157 establish a high probability as 95%. Therefore, the applicant is requested to provide additional information to support the basis for selecting the initial sample size.

(a) EPRI 107514 is applicable to Calvert Cliffs. The applicant is requested to clarify if application of this document represents industry consensus for selecting a sample size on a generic basis or if this 90/90 basis is plant specific.

(b) The applicant is requested to identify the size of the sample on the basis of 90/90 criteria versus 95/95 for each system or material and environment combination.

(c) The applicant is requested to provide justification for selecting a sample size based on the 90/90 criteria versus a more restrictive criteria of 95/95. For example, differentiate an approach for selecting a sample based on targeted inspections at susceptible locations versus a random sample or consider use of a risk-informed methodology.

TVA Response to Question 4

The use of EPRI 107514, "Age-Related Degradation Inspection Method and Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application," in the description of the Unit 1 Periodic Inspection Program has been deleted. The intent of this reference was to refer to the statistical sampling methodology presented in Chapter 4 of EPRI 107514, not the entire report. To clarify this situation, EPRI 107514 has been replaced by a reference to "Elementary Statistical Analysis" by S. S. Wilks (Reference 1) for a discussion of the statistical bases for determining an appropriate sample size for a generalized binomial distribution.

The sample selected for periodic inspection will be based on a 95/95 confidence level on a common material and environment bases. For example, where a common material, lay-up environment, and operating environment exist, the total population of restart inspections will be determined and a sample of re-inspection points, based on the criteria of 95/95, will be selected. The sample will be distributed among the various system locations that were grouped. If a criteria other than 95/95 is utilized, the deviation will be justified and NRC approval will be requested prior to implementing a differing criteria.

The description of the sampling methodology has been expanded in the revised version of the Unit 1 Periodic Inspection Program, Attachment 2. The sample size for the common material and environment groupings will be based on this formula for binomial distribution sampling, with the result rounded up to next whole number.

$$n = \left(\frac{z_\alpha^2 N}{\left(\frac{\rho(N-1)}{(1-\rho)} \right) + z_\alpha^2} \right)$$ Equation 10.18 (rearranged) - Reference 1.

For 95/95 confidence, $z_\alpha = 1.96$ (Table 10.1 - Reference 1) and $\rho = 0.05$ (probability of failure, i.e., 1-0.95). Substituting these values, this equation simplifies to:

$$n = \left(\frac{(72.99)N}{N + (71.99)} \right)$$

Where N is the total number of points in the original inspection population for a given grouping, and *n* is the required sample size.

NRC Question 5

For Element 2, Preventive Actions, the applicant identifies the Periodic Inspection Program as a "detection" program. Programs are normally termed as condition monitoring, performance monitoring or prevention and mitigation programs. The applicant is requested to clarify if this program is a condition monitoring program.

TVA Response to Question 5

The reference to "detection" program has been revised to "condition monitoring" program in Element 2 of the revised version of the Unit 1 Periodic Inspection Program (Attachment 2 of this enclosure).

NRC Question 6

The SRP-LR Section A.1.2.3.4 indicates that justification is required that the technique and frequency are adequate to detect the aging effects before loss of SC intended function. Under Element 4, Detection of Aging Effects, the applicant should include additional information (e.g., codes and standards, industry-wide operating experience) to demonstrate that the technique and frequency of future inspections, as determined by the outcome of initial inspections, is justified. For example, industry documents such as EPRI TR-107514 suggest that visual inspection may be an appropriate technique for certain aging mechanisms in addition to NDE.

TVA Response to Question 6

The Unit 1 Periodic Inspection Program is a plant unique inspection and trending program that is not covered by industry codes or standards. The selected inspection methodologies are based on the inspections performed to determine whether components require replacement prior to restart of BFN Unit 1. These methods are described in Response to Follow-Up to RAI 3.0-9 contained in the TVA Letter to the U.S. Nuclear Regulatory Commission, Document Control Desk, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Lay-up Program (TAC Nos. MC1704, MC1705, and MC1706)" dated May 18, 2005. To allow trending based on the

baseline developed prior to BFN Unit 1 restart, the inspection methodologies will be consistent with those utilized for the baseline inspections.

Based on the May 18, 2005 letter, the examination techniques utilized for the baseline inspections were ultrasonic thickness measurements for the piping and ultrasonic shear wave for welds. Element 4 of the revised Unit 1 Periodic Inspection Program has been enhanced to further describe the inspection methodologies (Attachment 2 of this enclosure).

NRC Question 7

For Element 5, Monitoring and Trending, the applicant should clarify that results will be monitored and trended.

TVA Response to Question 7

Element 5 of the revised version of the Unit 1 Periodic Inspection Program (Attachment 2 of this enclosure) has been revised to clarify the requirement to monitor and trend the results of the periodic inspections.

NRC Question 8

For Element 10, Operating Experience, the applicant should identify a commitment to provide (or have available for review) operating experience for this new program in the future to confirm its effectiveness.

TVA Response to Question 8

Element 10 of the revised version of the Unit 1 Periodic Inspection Program, Attachment 2, has be revised to clarify the requirement to evaluate the results of the periodic inspections to verify program effectiveness.

REFERENCES

1. S. S. Wilks, "Elementary Statistical Analysis," Princeton University Press, 1948

A.2.4 Unit 1 Periodic Inspection Program

The Unit 1 Periodic Inspection Program is a new program that performs periodic inspections of the non-replaced piping/fittings that were not in service supporting operation of Units 2 and 3 following the extended Unit 1 outage to verify that no latent aging effects are occurring, and to correct degraded conditions prior to loss of function.

During the Unit 1 restart project, examinations were performed to verify acceptability of the existing piping that was not replaced. The specific examinations are discussed in the TVA Letter to the U.S. Nuclear Regulatory Commission, Document Control Desk, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Lay-up Program (TAC Nos. MC1704, MC1705, and MC1706)" dated May 18, 2005. This piping is carbon/low alloy or stainless steel that was exposed to air, treated water, or raw water during the extended Unit 1 shutdown. The Unit 1 Periodic Inspection Program will examine a sample of those locations examined for plant restart as discussed in the referenced letter to verify that no latent aging effects are occurring. The sample size will be determined in accordance with the sampling methodology described in S. S. Wilks, "Elementary Statistical Analysis," Princeton University Press, 1948. If unacceptable degradation is identified, the sample size will be appropriately expanded. The initial sample, once selected, will be utilized in subsequent inspections, if practical.

These periodic inspections are in addition to the restart inspections performed prior to Unit 1 restart. The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation. The susceptible locations identified are those areas determined to have the highest potential for service induced wear or latent aging effects. The inspection techniques utilized evaluate internal conditions that are sensitive to the presence of unacceptable conditions including wear, erosion, and corrosion (including crevice corrosion) if present. For these locations, the restart inspections can be utilized as a baseline for comparison.

The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation and prior to the end of the current operating period. The second periodic inspection of all sample locations will be completed within the first ten

years of the period of extended operation. The inspection frequency is re-evaluated each time the inspection is performed and can be changed based on the trend of the results. The inspections will continue until the trend of the results provides a basis to discontinue the inspections.

B.2.1.42 Unit 1 Periodic Inspection Program

The Unit 1 Periodic Inspection Program is a new program that performs periodic inspections to verify that no latent aging effects are occurring and to correct degraded conditions prior to loss of function.

Aging Management Program Elements

The requirements of the Unit 1 Periodic Inspection Program are described below along with an evaluation of the program demonstrating compliance with the program elements of Appendix A of NUREG-1800.

Element 1 - Scope of Program

1. The specific program necessary for license renewal should be identified. The scope of the program should include the specific structures and components of which the program manages the aging.

BFN Description and Evaluation for Element 1

The Unit 1 Periodic Inspection Program provides periodic monitoring of the non-replaced piping/fittings that were not in service supporting operation of Units 2 and 3, as described in the TVA Letter to the U.S. Nuclear Regulatory Commission, Document Control Desk, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Lay-up Program (TAC Nos. MC1704, MC1705, and MC1706)" dated May 18, 2005.

The specific components included in the May 18, 2005 letter includes piping and welds in RHRSW (A&C loops in the tunnels), Fire Protection, EECW, RCW, CRD, CS, Feedwater, HPCI, Main Steam, RCIC, RHR, and RBCCW.

Element 2 - Preventive Actions

1. The activities for prevention and mitigation programs should be described. These actions should mitigate or prevent aging degradation.

2. For condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided. More than one type of aging management program may be implemented to ensure that aging effects are managed.

BFN Description and Evaluation for Element 2

The Unit 1 Periodic Inspection Program is a condition monitoring program and does not include preventive elements.

Element 3 - Parameters Monitored or Inspected

1. The parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s).

2. For a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. Some examples are measurements of wall thickness and detection and sizing of cracks.

3. For a performance monitoring program, a link should be established between the degradation of the particular structure or component intended function(s) and the parameter(s) being monitored. An example of linking the degradation of a passive component intended function with the performance being monitored is linking the fouling of heat exchanger tubes with the heat transfer intended function. This could be monitored by periodic heat balances. Since this example deals only with one intended function of the tubes, heat transfer, additional programs may be necessary to manage other intended function(s) of the tubes, such as pressure boundary.

   A performance monitoring program may not ensure the structure and component intended function(s) without linking the degradation of passive intended functions with the performance being monitored. For example, a periodic diesel generator test alone would not provide assurance that the diesel will start and run properly under all applicable design conditions. While the test verifies that the diesel will perform if all the support systems function, it provides little information related to the material condition of the support components and their ability to withstand DBE loads. Thus, a DBE, such as a seismic event, could cause the diesel supports, such as the diesel embedment plate anchors or the fuel oil tank, to fail if the effects of aging on these components are not managed during the period of extended operation.

4. For prevention and mitigation programs, the parameters monitored should be the specific parameters being controlled to achieve prevention or mitigation of aging effects. An example is the coolant oxygen level that is being controlled in a water chemistry program to mitigate pipe cracking.

BFN Description and Evaluation for Element 3

The Unit 1 Periodic Inspection Program is a condition monitoring program; thus, only the first two items for Element 3 are applicable.

The selected sample will be examined by the same (UT thickness for piping and UT shear wave and surface exam for welds), or equivalent, methodology as performed to determine acceptability of not replacing piping sections prior to restart. The susceptible locations identified in the RAI 3.0-9 response were those areas determined to have the highest potential for service induced wear or latent aging effects, which includes all types of corrosion. The inspection techniques utilized evaluate internal conditions and are sensitive to the presence of unacceptable conditions including wear, erosion, corrosion (including crevice corrosion) if present.

The sample selected for periodic inspection will be based on a 95/95 confidence level (Reference 1) on a common material and environment bases. For example, where a common material, lay-up environment, and operating environment exist, the total population of inspections that were performed to determine acceptability of not replacing piping sections will be determined and a sample of re-inspection points, based on the criteria of 95/95, will be selected. The sample will be distributed among the various system locations that were grouped based on a common material and environment. If a criterion other than 95/95 is utilized, the deviation will be justified and NRC approval will be requested prior to implementing a differing criteria.

The sample size for the common material and environment groupings will be based on this formula for binomial distribution sampling, with the result rounded up to next whole number.

$$n = \left(\frac{z_\alpha^2 N}{\left(\frac{\rho(N-1)}{(1-\rho)} \right) + z_\alpha^2} \right)$$

Equation 10.18 (rearranged) - Reference 1

For 95/95 confidence, $z_\alpha = 1.96$ (Table 10.1 - Reference 1) and $\rho = 0.05$ (probability of failure, i.e., 1-0.95). Substituting these values, this equation simplifies to:

$$n = \left(\frac{(72.99)N}{N + (71.99)} \right)$$

Where N is the total number of points in the original inspection population for a given grouping and *n* is required sample size.

Reference

1. S. S. Wilks, "Elementary Statistical Analysis," Princeton University Press, 1948.

Element 4 - Detection of Aging Effects

1. Detection of aging effects should occur before there is a loss of the structure and component intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the structure and component intended function(s) will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects. Provide information that links the parameters to be monitored or inspected to the aging effects being managed.

2. Nuclear power plants are licensed based on redundancy, diversity, and defense-in-depth principles. A degraded or failed component reduces the reliability of the system, challenges safety systems, and contributes to plant risk. Thus, the effects of aging on a structure or component should be managed to ensure its availability to perform its intended function(s) as designed when called upon. In this way, all system level intended function(s), including redundancy, diversity, and defense-in-depth consistent with the plant's CLB, would be maintained for license renewal. A program based solely on detecting structure and component failure should not be considered as an effective aging management program for license renewal.

3. This program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program).

4. The method or technique and frequency may be linked to plant-specific or industry-wide operating experience. Provide justification, including codes and standards referenced, that the technique and frequency are adequate to detect the aging effects before a loss of SC intended function. A program based solely on detecting SC failures is not considered an effective aging management program.

5. When sampling is used to inspect a group of SCs, provide the basis for the inspection population and sample size. The inspection population should be based on such aspects of the SCs as a similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects. The sample size should be based on such aspects of the SCs as the specific aging effect, location, existing technical information, system and structure design, materials of construction, service environment, or previous failure history. The samples should be biased toward locations most susceptible to the specific aging effect of concern in the period of extended operation. Provisions should also be included on expanding the sample size when degradation is detected in the initial sample.

BFN Description and Evaluation for Element 4

The Unit 1 Periodic Inspection Program is a plant unique inspection and trending program that is not covered by industry codes or standards. The selected inspection methodologies are based on the inspections performed to determine whether components require replacement prior to restart of BFN Unit 1. These methods are described in the TVA Letter to the U.S. Nuclear Regulatory Commission, Document Control Desk, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Lay-up Program (TAC Nos. MC1704, MC1705, and MC1706)" dated May 18, 2005. To allow trending based on the baseline developed prior to BFN Unit 1 restart, the inspection methodologies will be consistent with those utilized for the baseline restart inspections.

Based on the May 18, 2005, letter, the examination techniques utilized for the baseline inspections were ultrasonic thickness measurements for the piping and ultrasonic shear wave for welds.

The BFN Description and Evaluation for Element 3 portion of this attachment discusses sample selection. The selected re-inspection locations include those areas determined to have the highest potential for service induced wear or latent aging effects, which includes all types of corrosion. The inspection techniques utilized evaluate internal conditions that are sensitive to the presence of unacceptable conditions including wear, erosion, corrosion (including crevice corrosion) if present.

For the periodic inspection locations, the restart inspections can be utilized as a baseline for comparison. If required, a re-baseline will be performed on selected sample locations prior to restart to ensure accurate baseline values are available. The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation and prior to the end of the current operating period. The second periodic inspection of all sample locations will be completed within the first ten years of the period of extended operation. The inspection frequency is re-evaluated each time the inspection is performed and can be changed based on the trend of the results. The inspections will continue until the trend of the results provides a basis to discontinue the inspections.

Element 5 - Monitoring and Trending

1. Monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. Plant specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency.

2. This program element describes "how" the data collected are evaluated and may also include trending for a forward look. This includes an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection will occur before a loss of SC intended function. Although aging indicators may be quantitative or qualitative, aging indicators should be quantified, to the extent possible, to allow trending. The parameter or indicator trended should be described. The methodology for analyzing the inspection or test

results against the acceptance criteria should be described. Trending is a comparison of the current monitoring results with previous monitoring results in order to make predictions for the future.

BFN Description and Evaluation for Element 5

The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation and prior to the end of the current operating period. The second periodic inspection of all sample locations will be completed within the first ten years of the period of extended operation. The inspection frequency is re-evaluated each time the inspection is performed and can be changed based on the trend of the results. The inspections will continue until the trend of the results provides a basis to discontinue the inspections.

Element 6 - Acceptance Criteria

1. The acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation. The program should include a methodology for analyzing the results against applicable acceptance criteria. For example, carbon steel pipe wall thinning may occur under certain conditions due to erosion-corrosion. An aging management program for erosion-corrosion may consist of periodically measuring the pipe wall thickness and comparing that to a specific minimum wall acceptance criterion. Corrective action is taken, such as piping replacement, before reaching this acceptance criterion. This piping may be designed for thermal, pressure, NUREG-1800 A.1-6 April 2001 deadweight, seismic, and other loads, and this acceptance criterion must be appropriate to ensure that the thinned piping would be able to carry these CLB design loads. This acceptance criterion should provide for timely corrective action before loss of intended function under these CLB design loads.

2. Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the structure and component intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited.

3. It is not necessary to justify any acceptance criteria taken directly from the design basis information that is included in the FSAR because that is a part of the CLB. Also, it is not necessary to discuss CLB design loads if the acceptance criteria do not permit degradation because a structure and component without degradation should continue to function as originally designed. Acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads.

4. Qualitative inspections should be performed to same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site specific programs.

BFN Description and Evaluation for Element 6

The acceptance criterion for these periodic inspections is that the pipe wall will remain above minimum acceptable wall thickness until the next periodic inspection, and that no unacceptable weld cracks exist. The calculation for acceptable minimum wall considers stresses such as hoop, pressure, dead weight, thermal and seismic, as applicable based on the Code of Record and applicable approved code cases.

Element 7 - Corrective Actions

1. Actions to be taken when the acceptance criteria are not met should be described. Corrective actions, including root cause determination and prevention of recurrence, should be timely.

2. If corrective actions permit analysis without repair or replacement, the analysis should ensure that the structure and component intended function(s) will be maintained consistent with the CLB.

BFN Description and Evaluation for Element 7

The Corrective Action Program is administered by TVAN procedure SPP-3.1 in accordance with 10 CFR Part 50, Appendix B, and meets the conditions to be used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation.

Element 8 - Confirmation Process

Element 8 - Confirmation Process

1. The confirmation process should be described. It should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

2. The effectiveness of prevention and mitigation programs should be verified periodically. For example, in managing internal corrosion of piping, a mitigation program (water chemistry) may be used to minimize susceptibility to corrosion. However, it may also be necessary to have a condition monitoring program (ultrasonic inspection) to verify that corrosion is indeed insignificant.

3. When corrective actions are necessary, there should be follow-up activities to confirm that the corrective actions were completed, the root cause determination was performed, and recurrence is prevented.

BFN Description and Evaluation for Element 8

The Unit 1 Periodic Inspection Program is a condition monitoring program; thus, item 2 for Element 8 is not applicable.

See BFN Description and Evaluation for Element 7 for the remainder of Element 8.

Element 9 - Administrative Controls

1. The administrative controls of the program should be described. They should provide a formal review and approval process.

2. Any aging management programs to be relied on for license renewal should have regulatory and administrative controls. That is the basis for 10 CFR 54.21(d) to require that the FSAR supplement includes a summary description of the programs and activities for managing the effects of aging for license renewal. Thus, any informal programs relied on to manage aging for license renewal must be administratively controlled and included in the FSAR supplement.

BFN Description and Evaluation for Element 9

See BFN Description and Evaluation for Element 7. The proposed UFSAR description of the Unit 1 Periodic Inspection Program is provided in Attachment 1 of this enclosure.

Element 10 - Operating experience

1. Operating experience with existing programs should be discussed. The operating experience of aging management programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an aging management program because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

2. An applicant may have to commit to providing operating experience in the future for new programs to confirm their effectiveness.

BFN Description and Evaluation for Element 10

The Unit 1 Periodic Inspection Program is a new program that will monitor the operating condition of Unit 1 components that were not replaced during the Unit 1 restart. Therefore, there is no applicable operating experience for this inspection program.

The trending data developed in accordance with Element 5 demonstrates the effectiveness of the Unit 1 Periodic Inspection Program during the period of extended operation.

Conclusion

The Unit 1 Periodic Inspection Program is a new program identified to monitor system piping that did not require replacement following the extended Unit 1 outage. The Unit 1 Periodic Inspection Program will verify that no latent aging effects are occurring. The Unit 1 periodic inspections will be performed after Unit 1 is returned to operation and prior to the end of the current operating period. The second periodic inspection of all sample locations will be completed within the first ten years of the period of extended operation. The inspection frequency is re-evaluated each time the inspection is performed and can be changed based on the trend of the results. The inspections will continue

until the trend of the results provides a basis to discontinue the inspections.

ENCLOSURE 3

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING
OPEN ITEM OI 4.7.7, STRESS RELAXATION OF
CORE PLATE HOLD-DOWN BOLTS

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING OPEN ITEM OI 4.7.7, STRESS RELAXATION OF CORE PLATE HOLD-DOWN BOLTS

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning Open Item OI 4.7.7, Stress Relaxation of Core Shroud Hold-Down Bolts.

NRC Request

3. Open Item, OI 4.7.7 Stress Relaxation of Core Shroud Hold-Down Bolts - This topic needs additional discussion between the staff and TVA to resolve the issue satisfactorily. A follow-up conference call was conducted on October 18, 2005 between the NRC staff, TVA, and General Electric.

The summary of that call follows:

Background

For the period of extended operation, the projected loss of hold down bolt preload (stress relaxation) is taken as 20%, which bounds the original BWRVIP-25 analysis. With a loss of 20% preload, the applicant stated that sliding of the core plate under both normal and accident conditions will be prevented by friction due to initially imposed high bolt preload.

The staff requested that the applicant, TVA, demonstrate, based on a BWRVIP 25 type structural analysis, that the axial and bending stresses in the highest load bolts meet the ASME Section III allowable stresses considering the 20% decrease

in bolt preload at the end of the period of extended operation. By letter dated September 6, 2005, TVA provided an analysis showing that the axial bolt stresses meet the ASME Section III Class 1 Level D design allowable, and that bending of the hold down bolts does not occur, as a result of the prevention of sliding by the high preload and an assumed large friction coefficient.

Discussion

General Electric (GE) provided their methodology used applicable to BFN. In its information, GE did not use the staff approved analysis that was used in BWRVIP-25, "Core Plate Inspection Guidelines," report for the BFN units. The methodology used in the BWRVIP-25 report is more conservative. For BFN units, GE used a less conservative methodology, such as using a coefficient of friction value of 0.5 (dry environment) to ensure prevention of sliding of the core plate which eliminated the bending stresses in the core plate hold-down bolts. The staff determined that the methodology used for BFN units is not supported by the information provided in the literature. The staff position is that GE should apply the methodology that was agreed to have another conference call with the staff probably within 3 weeks to discuss this item.

The NRC staff needs supplemental information and identified the following concerns:

1. The analysis is significantly different from the structural analysis in BWRVIP 25, and is not based on a finite element model of the core plate.

2. Not clear if all loads listed in BWRVIP 25, such as fuel lift load, were included in the analysis.

3. The applicant selected friction due to high bolt preload (significantly larger than that specified in BWRVIP 25) as the means to prevent side motion of the core plate. BWRVIP 25 recommends the use of wedges to prevent side motion; it does not recommend high bolt preload and friction. The staff questions the basis for the applicant's choice.

4. The TVA analysis assumes a high static coefficient of dry friction as the mechanism to prevent side motion of the core plate. The staff questions the basis for this assumption for a core plate that is in a pressurized water environment.

5. Page 4-6 and Appendix A of BWRVIP 25 state that "of special interest is the amount of bending induced in the bolts when the core plate bows upward, or when load from the beams is no longer transferred to the rim." No such bending was evaluated in the TVA analysis.

6. The BWRVIP 25 structural analysis shows a variation of the axial forces in the hold down bolts with location around the plate circumference, and that the axial force in the highest-loaded bolts is about twice the mean axial bolt load. The TVA analysis shows that all bolts are uniformly loaded in tension. This indicates that the highest stresses in the hold down bolts have not been determined.

7. The effect of the large bolt preloads on the structural integrity of the core plate was not evaluated.

Based on the conference call TVA agreed that it needed further consultation with their vendor, GE, to resolve this issue. The staff identified that TVA needs to prioritize this issue whose resolution is very important in satisfactorily concluding the safety review and the progress so far made since March 2005 (when the problem was initially identified) is not entirely satisfactory. TVA took staff comments under advisement and agreed that they will impress upon the TVA's management to expeditiously resolve this item.

<u>TVA Response</u>

Commitment for BFN for the Core Plate Hold-Down Bolts:

TVA will perform a BFN plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand normal, upset, emergency, and faulted loads, as applicable, considering the effects of stress relaxation until the end of the period of extended operation. The installed core plate configuration and bolt preload will be used for the plant specific analysis. The analysis will use the plant-specific design basis loads and load combinations. The analysis will incorporate detailed flux/fluence analyses and improved stress relaxation correlations.

As per Browns Ferry's current licensing basis (Reference 1), the ASME Boiler and Pressure Code, Section III will be used as a guide in determining limiting stress intensities for reactor vessel internals. For those components for which

stresses exceed the ASME code allowables, either the elastic stability of the structure or the resulting deformation or displacement will be examined to determine if the safety design basis is satisfied.

Appropriate corrective action will be taken if the above plant-specific analysis does not satisfy the above criteria. The installation of core plate wedges to eliminate the need for the enhanced inspections of the core plate hold-down bolts as recommended by BWRVIP-25 is considered an acceptable corrective action.

The analysis or the corrective action taken to resolve this issue will be submitted to NRC for review 2 years prior to the period of extended operation.

Reference

1. Browns Ferry Updated Final Safety Analysis Report Volume 2, Section 3.3.5.1 Reactor Vessel Internals Mechanical Design. R21

ENCLOSURE 4

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING OPEN ITEM FROM AMP INSPECTION ON INSPECTION OF RESIDUAL HEAT REMOVAL SERVICE WATER (RHRSW) PIPING

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING OPEN ITEM FROM AMP INSPECTION ON INSPECTION OF RESIDUAL HEAT REMOVAL SERVICE WATER (RHRSW) PIPING

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning Open Item from AMP Inspection On Inspection of Residual Heat removal Service Water (RHRSW) Piping. The AMP Inspection is documented in NRC Letter to TVA dated November 8, 2005 Browns Ferry Nuclear Plant - Inspection Report 05000259-013, 05000260-013, and 05000296-013.

NRC Request

4. Open Item from AMR Inspection On Inspection of Residual Heat removal Service Water (RHRSW) Piping - This issue was identified during the regional inspection of license renewal for aging management review (AMR). TVA needs to provide appropriate response to the regional inspection team to satisfactorily resolve the issue prior to the next ACRS full committee meeting in March 2006.

TVA Response

The Residual Heat Removal Service Water (RHRSW) pump pit supplies water for both the RHRSW system and the Emergency Equipment Cooling Water (EECW) system. The RHRSW pump pit takes suction from three 24" cast iron pipes that are encased in concrete. These pipes are coated internally with cement. Each of the three 40 foot long pipes has a tee on the upstream end which receives raw cooling water from two Condenser Circulating Water (CCW) pump pits via sluice gate

valves located in the CCW pump pits. There are six sluice gates with two for each of the three encased pipes.

The three RHRSW inlet pipes are included in the BFN Open Cycle Cooling Water (OCCW) program. The inlets of these pipes are the injection point for corrosion inhibitors and biocides that are used to maintain the EECW System. The chemicals being injected at the inlet of these pipes are used to treat the other components in the OCCW system, including those components located in the RHRSW pump pits. These pipes receive the largest concentration of chemicals.

The sluice gate utilizes a local manual closure mechanism. The function of the sluice gate valves is to allow isolation of the encased pipe for RHRSW pump pit or CCW pump pit maintenance. The sluice gate has no active safety function other than remaining open to provide a flow path. The previously discussed raw water chemical treatment system injects chemicals or biocides immediately upstream of the sluice gates. The treated water immediately enters the throat of the valve and proceeds on to the imbedded piping. Substantial chemical treatment does not come into contact with the external portion of the sluice gate or its operator. Four of the six valves have been replaced in the past. The remaining two valves are scheduled to be replaced in January 2006.

As part of the License Renewal Process, an NRC inspection of Aging Management Programs (AMPs) was performed at Browns Ferry during the week of December 13, 2004. During this inspection, TVA indicated that a one time inspection of the external surfaces of the OCCW piping that is exposed to raw water would be performed. It was later determined that the external surface of the RHRSW pump pit inlet piping is encased in concrete and is not accessible for inspection. TVA did not specify an internal inspection for license renewal because the aging of the pipe internals is managed by compliance with the requirements of Generic Letter 89-13 which is consistent with requirements of NUREG 1801 for Aging Management Programs (AMPs) for Open Cycle Cooling Water Systems. In a follow-up NRC AMP inspection during the week of September 19, 2005, TVA was informed that the NRC's expectation was that an inspection be performed on the internal surfaces of the subject pipe.

Based on additional discussions with the NRC, BFN will perform the following three actions:

1. Perform a confirmatory inspection of the RHRSW pump pit supply piping using underwater cameras or other methods or techniques available at the time of the inspection. The inspection will include internal portions of one RHRSW pump pit supply pipe, and to the extent possible, will identify flow restrictions and material loss due to corrosion. The inspection will be performed from either the CCW Pump Pit or the RHRSW Pump Pit end of the pipe. This inspection will be performed prior to the period of extended operation.

2. BFN will include instructions in the CCW pump pit Preventive Maintenance Program to periodically inspect the sluice gate valves. This will be completed prior to the period of extended operation.

3. BFN will perform a confirmatory inspection of the seismic restraints in the RHRSW pump pit. This inspection will be performed prior to the period of extended operation.

ENCLOSURE 5

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING
OPERATING EXPERIENCE FOR UNIT 1 IN SATISFYING
THE INTENT OF THE LICENSE RENEWAL RULE

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING OPERATING EXPERIENCE FOR UNIT 1 IN SATISFYING THE INTENT OF THE LICENSE RENEWAL RULE

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning Operating Experience for Unit 1 in Satisfying the Intent of the License Renewal Rule.

NRC Request

5. The staff also discussed other issues from the committee's evaluation report comments/recommendations for which the staff is required to provide appropriate responses. It was agreed that the applicant will provide formal responses to these topics by November 15, 2005 as follows:

   A. Lack of operating experience for Unit 1 in satisfying the intent of the license renewal rule (10 CFR 54.17c). The staff provided a few examples of past exemptions provided to other applicants so that TVA could tailor their justifications for BFN Unit 1. The staff also discussed plausible compensatory actions such as, Unit 1 restart inspection, its operating history, replacement of piping and components which did not meet the reconstitution inspection criteria.

TVA Response

During the 526th meeting of the Advisory Committee on Reactor Safeguards, the Committee members asked that TVA clarify how the Browns Ferry Nuclear Plant (BFN), Unit 2 and 3, operating experience applies to Unit 1. As explained below, BFN has collective nuclear operating experience of approximately 51

years. This is sufficient to support the renewal of the Browns Ferry Unit 1 operating license because the Unit 2 operating experience, along with the experience during the ten-year extended layup and subsequent operation of BFN Unit 3, applies to Unit 1. Specifically, in pursuing license renewal for BFN Unit 1, TVA has relied not only on Unit 1's current licensing basis including the specific changes in Appendix F of the License Renewal Application, but also on Unit 1's plant-specific operating experience, the operating experience gained from the identical BFN Units 2 and 3, as well as relevant industry-wide operating experience. This experience base satisfies and is consistent with the regulatory requirements and intent of 10 CFR. 54.17(c).

By way of background, the Browns Ferry nuclear site consists of three units. The units share common facilities, materials, and environments. Each of the units are identical General Electric BWR 4 reactors with Mark I containments. TVA designed and constructed the units to be materially and operationally identical including systems, components, materials and environment. For a given power level, the system process conditions (e.g., pressure, temperatures, moisture content, chemical properties, flow rates, velocities, etc.) are identical. There is one Updated Final Safety Analysis Report for the three units. Operating procedures and Technical Specifications are nearly identical. Due to outage scheduling, small unit differences may exist for a short period of time but are eliminated as modifications are installed on the other units during subsequent unit outages.

In addition to the similarities between the Unit 2/3 and Unit 1 licensing and design bases, specific programs also function such that relevant Unit 2/3 operating experience is passed on to Unit 1. First, the TVA Corrective Action Program (CAP) applies to all TVA organizations involved in nuclear power activities. This program is not unit specific and, as applicable, a condition identified at any BFN unit is reviewed for generic implications potentially applicable to the other units. TVA also has an administrative procedure for the review and dissemination of operating experience obtained from both external and internal sources. This procedure requires screening of such information for potential BFN applicability. This information is received from sources such as NRC Information Notices, Institute of Nuclear Power Operations, NSSS vendor reports/ notices and in-house operating experience. If an item is determined to be applicable to BFN, then the information is addressed in the CAP. Thus, these programs help

ensure that relevant operating experience (OE) is applied to all three units.

Background

10 CFR 54.17(c) states that an application for a renewed license may not be submitted earlier than 20 years before the expiration of the operating license currently in effect. The operating license for BFN Unit 1 expires on December 20, 2013, for Unit 2 on June 28, 2014 and for Unit 3 on July 2, 2016. TVA submitted a single license renewal application for BFN Units 1, 2 and 3 to the NRC on December 31, 2003, thus satisfying the regulatory requirement in Section 54.17(c).

The BFN license renewal application satisfies not only the express requirements of Section 54.17(c), but also its underlying intent as it has evolved since its promulgation in 1991. In the 1991 Statements of Consideration (SOC) for Part 54 Nuclear Power Plant License Renewal (56 FR 64963), the Commission imposed a twenty-year threshold limit to ensure that substantial operating experience is accumulated by licensees before the submittal of license renewal applications. When Part 54 was promulgated nearly fifteen years ago, the Commission originally determined that a twenty-year period of plant-specific operating experience would allow adequate assessment of any age-related degradation of plant structures, systems and components. The 1991 SOC also noted, however, that licensees and the NRC would have the benefit of nuclear industry operating experience and would not be limited to information developed solely by an applicant seeking a renewed license.

In 1995, the NRC amended the Part 54 regulations to revise the requirements an applicant must meet for obtaining the renewal of an operating license. As part of the 1995 SOC for the amended rule (60 FR 22487), the NRC included public responses to five questions posed by the NRC in the supplementary information accompanying the proposed rule. One of these questions dealt specifically with whether sufficient plant-specific history before 20 years of operation would provide reasonable assurance that aging concerns would be identified. In answer to the question, the Department of Energy noted that, in general, aging effects are apparent after only a few years of operation and that industry-wide data provide a sound basis to understand and address the effects of aging, even at a plant that has operated only a few years.

The Commission also indicated that it was willing to consider plant-specific exemptions to justify applying for a renewed license prior to 20 years from the expiration date of the current license (60 FR 22488). Indeed, since 1995, the NRC has granted several plant-specific exemption requests to licensees to allow application for license renewal prior to 20 years from expiration of the current operating license. In issuing these exemptions, NRC has consistently broadened the scope of relevant operating experience supporting license renewal applications to include that of sister-units and industry-wide experience. In granting an exemption from 10 CFR 54.17(c) to Nine Mile Point 2, for example, the NRC credited the similar operation, maintenance, sharing of operating experience and environment between Nine Mile Point Unit 1 and Unit 2.

BFN Operating Experience

BFN Unit 1 was licensed and began initial operation in 1973. Unit 2 began operation in 1974. Unit 1 and 2 operated until March 22, 1975, at which time both units were shut down due to a fire in the Unit 1 reactor building. Units 1 and 2 resumed operation in 1976, and Unit 3 began initial operation in 1977. All three units were operated until March 1985, at which time TVA voluntarily shut them down to address regulatory and management issues.

Following successful resolution of the management issues and the Unit 2 and common regulatory issues, Unit 2 was restarted on May 23, 1991. Unit 3 remained in a layup/ recovery mode for approximately 10 years and, following resolution of the Unit 3 regulatory issues, Unit 3 was restarted on November 19, 1995. Both Units 2 and 3 have operated with high capacity factors into the present time. In the early 1990's, TVA decided to defer restart of BFN Unit 1.

On May 16, 2002, TVA announced the Unit 1 Restart Project. As part of the restart project, TVA is performing the same restart programs and implementing the same modifications that were previously completed on Units 2 and 3. At restart, Unit 1 will be operationally the same as Units 2 and 3. Based only on the periods of operation as of 2005, Unit 1 has operated for approximately 10 calendar years, Unit 2 has operated for approximately 23 calendar years and Unit 3 has operated for approximately 18 calendar years.

During the above described periods of operation, the three units have experienced similar aging mechanisms. For example, each unit has experienced the expected wear such as Flow Accelerated Corrosion (FAC), general corrosion, and

microbiologically induced corrosion (MIC). Applicable aging mechanisms for the passive plant features are identified in Section 3.0 of the BFN License Renewal Application (LRA). The aging mechanisms for the passive plant features are well known and are addressed by existing plant programs and procedures.

TVA has effectively managed aging through various programs and has replaced and upgraded the plant to manage the effects of aging. For example, the systems susceptible to FAC are monitored in accordance with EPRI guidelines (LRA Section B.2.1.15). Piping on Units 2 and 3 is monitored for FAC-induced wear and replaced as needed. In many cases, the piping has been replaced with FAC-resistant chrome molybdenum piping (LRA Section B.2.1.15). Reactor vessel components such as the shroud, vessel welds, jet pumps, core plate and top guide are inspected by accepted industry standards such as the Boiling Water Reactor Vessel Internals Program (BWRVIP) and repairs/replacements performed as required (LRA Section B.2.1.12). Raw water piping that is used to transfer heat from safety related systems to the ultimate heat sink is managed by the Open Cycle Cooling Water System Program (LRA Section B.2.1.17). The primary containment liner is inspected in accordance with American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI, Subsection IWE for steel containments (Class MC) requirements (LRA Section B.2.1.31). As explained in the license renewal application, these same programs are used on all three units.

As part of the recovery of Units 2 and 3, TVA implemented various plant upgrades (i.e., design changes) in response to regulatory issues and/or to improved plant operating characteristics. This experience has been brought to bear in the Unit 1 recovery effort. For example, as part of the recovery of Units 2 and 3, TVA replaced piping that was susceptible to Intergranular Stress Corrosion Cracking (IGSCC). Similar design changes are being installed on Unit 1 as part of the recovery process. IGSCC susceptible piping in the Reactor Recirculation, Residual Heat Removal, Reactor Water Cleanup and Core Spray systems on Unit 1 is being replaced using materials which are resistant to IGSCC.

The Unit 1 restart project incorporates extensive activities to replace, upgrade and refurbish components and to implement lessons learned from Units 2 and 3 operating experience. Unit 1 restart activities include modifying the Unit 1 licensing basis to make it consistent with the current licensing basis of Units 2 and 3. Appendix F of the License

Renewal Application lists the modifications and programs that have already been implemented on Units 2 and 3 and are being completed on Unit 1 as part of the restart project. These differences will be eliminated prior to the restart of Unit 1 in May 2007. The design changes will result in the three units having the same licensing basis and being operationally identical using the same plant process conditions and the same materials of construction. The Unit 1 recovery design changes have not resulted in any different types of materials being installed than are present in Units 2 and 3.

Since components and structures within the scope of aging management reviews (AMRs) for the three units contain the same materials and experienced the same process conditions, all three units experience similar aging effects. Unit 1 has been shut down since 1985. During the shutdown period, it experienced aging effects analogous to those experienced on Units 2 and 3 during their shutdown periods. In this regard, TVA has utilized the operating experience gained from restarting and operating Units 2 and 3, in recovering Unit 1, and has undertaken proactive steps to use the aging mechanisms experienced during subsequent operation of Units 2 and 3 to determine the necessary modifications to Unit 1 to preclude aging effects when possible. In many cases, the aging mechanisms such as FAC had not resulted in significant wear in Unit 1; however, the recovery effort has replaced the FAC-susceptible material with FAC-resistant material. The Unit 1 locations for replacements were expanded to address additional locations with geometry/process conditions similar to Units 2 and 3 wear locations even if Unit 2 and 3 had not experienced significant wear in all similar locations. For example, if Unit 2 had experienced wear at one elbow, but not at two other elbows of similar material/geometry/process conditions, the Unit 1 restart scope included all 3 locations.

The Unit 1 inspections/programs for other aging mechanisms have been expanded in a similar fashion to proactively prevent age related wear. The scope of replacement of piping that is IGSCC susceptible is significantly larger in Unit 1 than in Units 2 or 3, and thus, Unit 1 will contain a significantly larger scope of new pipe which has no pre-existing aging effects. Since similar materials and geometry were used in Unit 1 for the expanded scope, there were no new aging mechanisms introduced.

In addition, the Unit 1 systems that perform a required function in the defueled condition, or that directly support Unit 2 or Unit 3 operation, have been continuously operated and maintained under applicable Technical Specifications and plant programs since shutdown in 1985. This OE has been factored into the license renewal application. Examples of these piping systems are:

- Fuel Pool Cooling System
- Portions of the Control Rod Drive (CRD) System
- Portions of the Raw Cooling Water (RCW) System
- Portions of the Reactor Building Closed Cooling Water (RBCCW) System
- Portions of the Residual Heat Removal (RHR) System
- Portions of the Residual Heat Removal Service Water (RHRSW) System
- Portions of the Emergency Equipment Cooling Water (EECW) System
- Portions of the Control Air System

TVA maintained the Unit 1 systems in a physical condition during shutdown similar to that of Units 2 and 3 during their shutdown periods. The internal operating conditions (e.g., water chemistry, flow rate, temperature, etc.) for these systems are the same as those found in the operating units. These systems have experienced the same aging mechanisms and rates as experienced by the similar Unit 2 and 3 systems for shutdown conditions. The Unit 1, 2 and 3 reactor buildings are one continuous structure, and the external operating environments of the systems are the same. Even though Unit 1 was in an extended outage, the overall environmental conditions affecting external surfaces in Unit 1 was maintained consistent with Units 2 and 3. Unit 1 had the normal ventilation systems in service and equipment was maintained to prevent system leakage so that the equipment was not subjected to aggressive external conditions.

Other Unit 1 systems have been in a layup condition, and this prior layup experience has been applied to Unit 1 license renewal. For example, Unit 1 was placed in layup using the same philosophy, processes and conditions as used for Unit 3. Some piping systems (or portions of piping systems) were placed into a "wet layup" under TVA's Unit 1 layup procedure, including:

- Reactor Vessel
- Reactor Water Recirculation System
- Reactor Water Cleanup System

- Portions of the Residual Heat Removal (RHR) System
- Portions of the Core Spray (CS) System
- Portions of the Feedwater (FW) System

The water chemistry within these Unit 1 piping systems was monitored for compliance with the water quality requirements. Thus, it would not be expected that a different aging mechanism or rate would exist in wet layup compared to what would have occurred if the system were in normal operation. The full scope of BWRVIP inspections have been performed on the Unit 1 reactor vessel as part of the restart project. No adverse effects from the layup period were found and repairs/ replacements not related to layup will be performed as required. The reactor water recirculation system and reactor water cleanup system piping, both large bore and small bore, have been replaced. The residual heat removal and core spray piping that was in wet layup has also been replaced. The piping was replaced with the same materials that were used in Unit 2 and 3. Ultrasonic inspections of the feedwater piping have confirmed that the piping does not exhibit adverse effects from the wet layup period. Thus, extensive layup experience has been applied to Unit 1 license renewal.

Some Unit 1 piping systems (or portions of piping systems) were drained and placed in dry layup, including:

- Reactor Core Isolation Cooling (RCIC) System
- High Pressure Coolant Injection (HPCI) System
- Main Steam (MS) System
- Portions of the Residual Heat Removal (RHR) System
- Portions of the Core Spray (CS) System
- Portions of the Feedwater (FW) System

The exterior of the system/component was maintained at nominal reactor or turbine buildings ambient conditions which would have been the same in Units 1, 2, and 3. Thus, the dry layup systems would have experienced aging at a rate less than or equal to that of the corresponding Unit 2/3 system.

Some Unit 1 systems were simply drained with no controlled environment. As a result, portions of two Unit 1 systems experienced accelerated aging. The accelerated aging of these systems was previously identified as part of the operating experience from the Unit 3 outage between 1985 and 1995. These were portions of the Unit 1 Residual Heat Removal Service Water (RHRSW) piping inside the Reactor Building and some small bore Raw Cooling Water piping. As

explained below, this prior Unit 2/Unit 3 OE was incorporated into Unit 1 aging management activities.

The RHRSW piping normally contains raw water from the river. Some of the Unit 1 RHRSW piping inside the reactor building was drained in 1985, but moisture laden air remained in the system. The piping enters/exits from the RHRSW tunnels. Inside the tunnels, the piping is exposed (i.e., not buried) for approximately 100 feet after which it becomes buried pipe out to the intake pumping station. The buried piping could not be drained since it is below grade. Water from the buried section of piping vaporized and entered the drained, above grade piping in both the tunnels and the Reactor Building. Inside the RHRSW tunnels which are approximately 20 feet under an earthen berm, the ambient temperature was cool and no adverse reactions occurred inside the RHRSW piping. However, the RHRSW piping inside the Reactor Building experienced normal ambient conditions (i.e., 65°F to 90°F). In this warm, moisture laden environment, severe corrosion occurred that necessitated the complete replacement of the pipe. As shown by ultrasonic measurements of pipe wall thickness and visual observations of pipe interiors, this aging effect was not experienced by buried pipe or above grade pipe which was full of water. This aging effect was restricted to the RHRSW system because it is the only system that was drained but allowed to contain moisture laden air. This aging was first identified on Unit 3 during the Unit 3 recovery and necessitated the replacement of all of the RHRSW piping inside the unit 3 reactor building. Based on this lesson learned, the required pipe replacement was performed for the Unit 1 A and C loops RHRSW piping which had been laid-up in a similar fashion to the Unit 3 piping.

The small bore Raw Cooling Water (RCW) piping was drained. However, due to valve leakage, some water was reintroduced into the system. The combination of water and trapped air set up virtually the same corrosion effects described above for the RHRSW piping. The Unit 1 recovery project has visually and ultrasonically inspected the small bore raw water piping and is replacing approximately 3000 feet of degraded piping.

The Unit 1 restart project did not credit the Unit 1 layup program as the sole means of establishing the acceptability of the associated piping and components for restart. TVA either replaced the piping and components or performed appropriate visual and/or ultrasonic inspections as discussed in Reference 1, to establish the physical condition of

systems and components not being replaced. For systems, piping and components that were replaced, no layup effects are present. The Unit 1 structures, systems and components in the license renewal scope will be subject to the existing BFN aging management programs.

Additional Compensatory Measures

In addition, to further compensate for the limited duration of Unit 1-specific OE, and to ensure there are no latent aging effects as a result of the layup program, BFN will implement a targeted periodic inspection program for Unit 1 system piping that was not replaced as part of the Unit 1 restart project. The restart inspections will provide baseline measurements for targeted inspections to be performed after the unit is returned to operation to verify aging management program effectiveness and to verify the absence of additional latent aging effects. The selected sample will be examined by the same or equivalent methodology as used during restart. Systems (or portions of systems) for which periodic inspections will be performed include MS, FW, RHRSW, RCW, EECW, Fire Protection, Reactor Building Closed Cooling Water, RCIC, HPCI, RHR and Control Rod Drive.

After restart in 2007, Unit 1 would have six years of operation remaining in the current license period, prior to the period of extended operation. The first periodic inspection will be performed during the current license period. An inspection also will be performed during the period of extended operation. Subsequent inspection frequency will be determined based on the inspection results. Inspections will continue until the trend of results provides a basis to discontinue the inspection. There is reasonable confidence that these periodic inspections will be capable of detecting degradation caused by potential latent aging effects after the systems are returned to service.

As part of the aging management review in support of the License Renewal Application, TVA recognized the possibility that the Unit 1 operating experience may not be exactly the same as the operating experience on Units 2 and 3 due to the layup period. Thus, as a further compensatory action, TVA performed evaluations to identify new aging effects that could be applicable to Unit 1 as a result of the layup environment. The material groupings and aging effects were established using the same approach as utilized in the rest of the License Renewal application. A detailed evaluation was performed for nineteen Unit 1 systems. Based on these additional evaluations, TVA concluded that there were no new

Unit 1 aging effects requiring management during the renewal term. A summary of these evaluations is provided in Section 3.0.1 of the License Renewal application. TVA provided additional details of this evaluation in Reference 2.

Summary and Conclusion

Unit 3 was shut down for approximately 10 years; from 1985 to 1995. The unit was placed in layup using the same philosophy, processes and conditions as used for Unit 1. The aging effects on Unit 3 were monitored and addressed prior to startup in 1995. Since 1995, Unit 3 has operated with a high capacity factor and was uprated 5% reactor thermal power in 1998. During this 10-year period of operation, no additional aging effects have been identified attributable to the 10 years of shutdown and layup. Since Unit 1 was laid up and maintained using the same method as Unit 3, the aging effects during the layup and subsequent operation of Unit 3 would be expected to apply equally to Unit 1. Unit 2 and 3 operation including power up-rate has not resulted in any unexpected aging mechanisms or rates. Unit 1 operation following the shutdown and associated replacements/refurbishments is expected to exhibit the same aging mechanisms and rates as Units 2 and 3.

In addition, aside from layup-related operating experience, BFN Units 1, 2, and 3 are operationally identical. Over 51 years of operating experience is available and has been used to support the preparation of the three-unit license renewal application. This operating experience has been relied upon in performing the aging management reviews described in the LRA. Appendix F of the License Renewal Application describes the differences between Unit 1 and Units 2 and 3. These differences will be eliminated prior to the restart of Unit 1 in May 2007. Based on the similarity in design, operation, materials and environment between BFN Units 2 and 3 and Unit 1, it is logical and reasonable to apply the operating, (i.e., shutdown and pre/post-shutdown) experience from Units 2 and 3 to Unit 1. As an additional compensatory measure, TVA will perform targeted periodic inspections for Unit 1 systems that were not replaced as part of the Unit 1 Restart Project. These inspections will provide heightened assurance that existing AMPs address relevant aging mechanisms and effects for Unit 1.

<u>References</u>:

1. TVA letter to NRC dated May 18, 2005, Browns Ferry Nuclear Plant (BFN) - Units 1, 2 and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Layup Program (TAC Nos. MC1704, MC1705, and MC1706)

2. TVA letter to NRC dated February 19, 2004, Browns Ferry Nuclear Plant (BFN) - Units 1, 2 and 3 - January 28, 2004 Meeting Follow-up - Additional Information

ENCLOSURE 6

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING
INPUT FOR WET LAYUP SECTION OF THE SER

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING INPUT FOR WET LAYUP SECTION OF THE SER

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning Input for Wet Layup Section of the SER.

NRC Request

5. The staff also discussed other issues from the committee's evaluation report comments/recommendations for which the staff is required to provide appropriate responses. It was agreed that the applicant will provide formal responses to these topics by November 15, 2005 as follows:

   B. Providing suitable input for the Wet Layup sections for the SER so the staff can write a cohesive safety evaluation on the applicability of Unit 2 & 3 experience to Unit 1.

TVA Response

The following write-up is provided as the requested input:

BFN Unit 1 was licensed and began initial operation in 1973. Unit 2 began operation in 1974. Units 1 and 2 operated until March 22, 1975, at which time both units were shut down due to a fire in the Unit 1 reactor building. Units 1 and 2 resumed operation in 1976 and Unit 3 began initial operation in 1977. All three units were operated until March 1985, at which time TVA voluntarily shut them down to address regulatory and management issues.

Following successful resolution of the management issues and the Unit 2 and common regulatory issues, Unit 2 was restarted on May 23, 1991. Unit 3 remained in a layup/recovery mode for approximately 10 years and, following resolution of the Unit 3 regulatory issues, it was restarted on November 19, 1995. Both Units 2 and 3 have operated with high capacity factors into the present time. In the early 1990's, TVA decided to defer restart of BFN Unit 1.

On May 16, 2002, TVA announced the Unit 1 Restart Project. As part of the restart project, TVA is performing the same restart programs and implementing the same modifications that were previously completed on Units 2 and 3. At restart, Unit 1 will be operationally the same as Units 2 and 3. The current planned restart date for Unit 1 is May 2007.

The Unit 1 systems that perform a required function in the defueled condition, or that directly support Unit 2 or Unit 3 operation, have been continuously operated and maintained under applicable Technical Specifications and plant programs since shutdown in 1985. Examples of these piping systems are:

- Fuel Pool Cooling System
- Portions of the Control Rod Drive (CRD) System
- Portions of the Raw Cooling Water (RCW) System
- Portions of the Reactor Building Closed Cooling Water (RBCCW) System
- Portions of the Residual Heat Removal (RHR) System
- Portions of the Residual Heat Removal Service Water (RHRSW) System
- Portions of the Emergency Equipment Cooling Water (EECW) System
- Portions of the Control Air System

TVA maintained the Unit 1 systems in a physical condition during shutdown similar to that of Units 2 and 3 during their shutdown periods. The internal operating conditions (e.g., water chemistry, flow rate, temperature, etc.) for these systems are the same as those found in the operating units. These systems have experienced the same aging mechanisms and rates as experienced by the similar Units 2 and 3 systems for shutdown conditions. The Units 1, 2, and 3 reactor buildings are one continuous structure, and the external operating environments of the systems are the same. Even though Unit 1 was in an extended outage, the overall environmental

conditions affecting external surfaces in Unit 1 was maintained consistent with Units 2 and 3. Unit 1 had the normal ventilation systems in service and equipment was maintained to prevent system leakage so that the equipment was not subjected to aggressive external conditions.

Other Unit 1 systems have been in a layup condition, and prior layup experience from Unit 3 has been applied to Unit 1 license renewal. For example, Unit 1 was placed in layup using the same philosophy, processes and conditions as used for Unit 3. Some piping systems (or portions of piping systems) were placed into a "wet layup" under TVA's Unit 1 layup procedure, including:

- Reactor Vessel
- Reactor Water Recirculation System
- Reactor Water Cleanup System
- Portions of the Residual Heat Removal (RHR) System
- Portions of the Core Spray (CS) System
- Portions of the Feedwater (FW) System

The water chemistry within these Unit 1 piping systems was monitored for compliance to the water quality requirements. Thus, it would not be expected that a different aging mechanism or rate would exist in wet layup compared to what would have occurred if the system were in normal operation. The full scope of BWRVIP inspections have been performed on the Unit 1 reactor vessel as part of the restart project. No adverse effects from the layup period were found and repairs/replacements not related to layup will be performed as required. The reactor water recirculation system and reactor water cleanup system piping, both large bore and small bore, have been replaced. The residual heat removal and core spray piping that was in wet layup has also been replaced. The piping was replaced with the same materials that were used in Units 2 and 3. Ultrasonic inspections of the feedwater piping have confirmed that the piping does not exhibit adverse effects from the wet layup period.

Some Unit 1 piping systems (or portions of piping systems) were drained and placed in dry layup, including:

- Reactor Core Isolation Cooling (RCIC) System
- High Pressure Coolant Injection (HPCI) System
- Main Steam (MS) System
- Portions of the Residual Heat Removal (RHR) System

- Portions of the Core Spray (CS) System
- Portions of the Feedwater (FW) System

The exterior of the system/component was maintained at nominal reactor or turbine buildings ambient conditions which would have been the same in Units 1, 2, and 3. Thus, the dry layup systems would have experienced aging at a rate less than or equal to that of the corresponding Unit 2/3 system.

Some Unit 1 systems were simply drained with no controlled environment. As a result, portions of two Unit 1 systems experienced accelerated aging. The accelerated aging of these systems was previously identified as part of the operating experience from the Unit 3 outage between 1985 and 1995. These were portions of the Unit 1 Residual Heat Removal Service Water (RHRSW) piping inside the Reactor Building and some small bore Raw Cooling Water piping. As explained below, this prior Unit 2/Unit 3 operating experience was incorporated into Unit 1 aging management activities.

The RHRSW piping normally contains raw water from the river. Some of the Unit 1 RHRSW piping inside the reactor building was drained in 1985, but moisture laden air remained in the system. The piping enters/exits from the RHRSW tunnels. Inside the tunnels, the piping is exposed (i.e., not buried) for approximately 100 feet after which it becomes buried pipe out to the intake pumping station. The buried piping could not be drained since it is below grade. Water from the buried section of piping vaporized and entered the drained, above grade piping in both the tunnels and the Reactor Building. Inside the RHRSW tunnels, which are approximately 20 feet under an earthen berm, the ambient temperature was cool and no adverse reactions occurred inside the RHRSW piping. However, the RHRSW piping inside the Reactor Building experienced normal ambient conditions (i.e., 65°F to 90°F). In this warm, moisture-laden environment, severe corrosion occurred that necessitated the complete replacement of the pipe. As shown by ultrasonic measurements of pipe wall thickness and visual observations of pipe interiors, this aging effect was not experienced by buried pipe or above grade pipe which was full of water. This aging effect was restricted to the RHRSW system because it is the only system that was drained but allowed to contain moisture-laden air. This aging was first identified on Unit 3 during the Unit 3 recovery and necessitated the replacement of all of the RHRSW piping inside the Unit 3 reactor building. Based on this lesson learned, the required pipe replacement was performed

for the Unit 1 A and C loops RHRSW piping which had been laid-up in a similar fashion to the Unit 3 piping.

The small bore Raw Cooling Water (RCW) piping was drained. However, due to valve leakage, some water was reintroduced into the system. The combination of water and trapped air set up virtually the same corrosion effects described above for the RHRSW piping. The Unit 1 recovery project has visually and ultrasonically inspected the small bore raw water piping and is replacing approximately 3000 feet of degraded piping.

The Unit 1 restart project did not credit the Unit 1 layup program as the sole means of establishing the acceptability of the associated piping and components for restart. TVA either replaced the piping and components or performed appropriate visual and/or ultrasonic inspections as discussed in Reference 1, to establish the physical condition of systems and components not being replaced. For systems, piping, and components that were replaced, no layup effects are present. The Unit 1 structures, systems and components in the license renewal scope will be subject to the existing BFN aging management programs.

To ensure there are no latent aging effects as a result of the layup program, BFN will implement a targeted periodic inspection program for Unit 1 system piping that was not replaced as part of the Unit 1 restart project. The restart inspections will provide baseline measurements for targeted inspections to be performed after the unit is returned to operation to verify aging management program effectiveness and to verify the absence of additional latent aging effects. The selected sample will be examined by the same or equivalent methodology as used during restart. Systems (or portions of systems) where periodic inspections will be performed include MS, FW, RHRSW, RCW, EECW, Fire Protection, Reactor Building Closed Cooling Water, RCIC, HPCI, RHR and Control Rod Drive.

After restart in 2007, Unit 1 would have six years of operation remaining in the current license period, prior to the period of extended operation. The first periodic inspection will be performed during the current license period. An inspection also will be performed during the period of extended operation. Subsequent inspection frequency will be determined based on the inspection results. Inspections will continue until the trend of results provides a basis to discontinue the inspection. There is reasonable

confidence that these periodic inspections will be capable of detecting degradation caused by potential latent aging effects after the systems are returned to service.

As part of the aging management review in support of the License Renewal Application, TVA recognized that the Unit 1 operating experience may not be the same as the operating experience on Units 2 and 3 due to the layup period. Thus, as a further compensatory action, TVA performed evaluations to identify new aging effects that could be applicable to Unit 1 as a result of the layup environment. The material groupings and aging effects were established using the same approach as utilized in the rest of the License Renewal application. A detailed evaluation was performed for nineteen Unit 1 systems. It was concluded that there were no new aging effects requiring management during the renewal term. A summary of these evaluations is provided in Section 3.0.1 of the License Renewal Application. TVA provided additional details of this evaluation in Reference 2.

Unit 3 was shut down for approximately 10 years; from 1985 to 1995. The unit was placed in layup using the same philosophy, processes and conditions as used for Unit 1. The aging effects on Unit 3 were monitored and addressed prior to startup in 1995. Since 1995, Unit 3 has operated with a high capacity factor and was uprated 5% reactor thermal power in 1998. During this 10-year period of operation, no additional aging effects have been identified attributable to the 10 years of shutdown and layup. Since Unit 1 was laid up and maintained using the same method as Unit 3, the aging effects during the layup and subsequent operation of Unit 3 would be expected to apply equally to Unit 1. Units 2 and 3 operation including power up-rate has not resulted in any unexpected aging mechanisms or rates. Unit 1 operation following the shutdown and associated replacements/refurbishments is expected to exhibit the same aging mechanisms and rates as Units 2 and 3.

The Unit 1 restart project did not credit the Unit 1 layup program as the sole means of establishing the acceptability of the associated piping and components for restart. TVA either replaced the piping and components or performed appropriate visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. For systems, piping and components that were replaced, no layup effects are present. As a compensatory measure for systems and components not being replaced, TVA

will perform targeted periodic inspections for the Unit 1 systems that were not replaced as part of the Unit 1 Restart Project. These inspections will provide heightened assurance that existing AMPs address relevant aging mechanisms and effects for Unit 1.

References:

1. TVA letter to NRC dated May 18, 2005, Browns Ferry Nuclear Plant (BFN) - Units 1, 2 and 3 - License Renewal Application (LRA) - Response to NRC Request for Additional Information Concerning the Unit 1 Layup Program (TAC Nos. MC1704, MC1705, and MC1706)
2. TVA letter to NRC dated February 19, 2004, Browns Ferry Nuclear Plant (BFN) - Units 1, 2 and 3 - January 28, 2004 Meeting Follow-up - Additional Information

ENCLOSURE 7

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING
CLARIFICATION OF ONE-TIME INSPECTION PROGRAM VERSUS
UNIT 1 PERIODIC INSPECTION PROGRAM

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

RESPONSE TO NRC REQUEST FOR SUPPLEMENTAL RESPONSE CONCERNING CLARIFICATION OF ONE-TIME INSPECTION PROGRAM VERSUS UNIT 1 PERIODIC INSPECTION PROGRAM

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3. As part of its review of TVA's LRA, the NRC staff, through a letter dated October 31, 2005, (ADAMS Accession No. ML053050358) requested supplemental responses needed to address four open items included in the Advisory Committee on Reactor Safeguards Interim evaluation of BFN's License Renewal Application and the NRC's draft Safety Evaluation Report.

This enclosure provides the supplemental response to the NRC's request concerning Clarification of the One-Time Inspection Program Versus the Unit 1 Periodic Inspection Program.

NRC Request

5. The staff also discussed other issues from the committee's evaluation report comments/recommendations for which the staff is required to provide appropriate responses. It was agreed that the applicant will provide formal responses to these topics by November 15, 2005 as follows:

   C. Clarification of One-Time Inspection Program Versus Unit 1 Periodic Inspection Program and the One-Time Inspection Program consistency with GALL.

TVA Response

The following marked-up pages of applicable pages of the SER provide the requested clarification.

OI-4.7.7: (Section 4.7.7 - Stress Relaxation of the Core Plate Hold-Down Bolts)

In LRA Section 4.7.7, the loss of preload of the core plate hold-down bolts due to thermal and irradiation effects was evaluated in accordance with the requirements of 10 CFR 54.21(c)(1)(ii). For the 40-year lifetime, the BWRVIP-25 concluded that all core plate hold-down bolts will maintain some preload throughout the life of the plant. For the period of extended operation, the expected loss of preload was assumed to be 20 percent, which bounds the original BWRVIP analysis that was prepared to bound the majority of plants, including BFN units after operating for 20 additional years. With a loss of 20 percent in preload, the core plate will maintain sufficient preload to prevent sliding under both normal and accident conditions. Based on this assumption, the applicant concluded that the loss of preload is acceptable for the period of extended operation.

In RAI 4.7.7-1, the staff requested the applicant to demonstrate how the BWRVIP-25 analysis can be applied to the BFN units based on the configuration and the geometry of core plate hold-down bolts and the reactor environment (temperature and neutron fluence) assumed in the original report. The staff requested from the vendor plant-specific calculation that will validate the assumption as stated above.

This evaluation is still ongoing and is not yet resolved. **This is open item (OI) 4.7.7-1.**

1.6 Summary of Confirmatory Items

As a result of the staff's review of the LRA for BFN, including additional information and clarifications submitted to the staff through June 15, 2005, the staff identified the following confirmatory items (CIs). An issue is considered confirmatory if the staff and the applicant have reached a satisfactory resolution, but the resolution has not yet been formally submitted to the staff. Each CI has been assigned a unique identifying number. The items identified in this section have been properly closed by the technical staff.

CI-3.0-3 LP: (Section 3.0 - LayUp Program)

Unit 1 is currently on an administrative hold and kept in a layup status since its voluntary shutdown in March 1985. The applicant intends to restart Unit 1 in 2007 and has since completed Unit 1 wide refurbishment and replacement of piping and components as necessary, the details of which are elaborated in SER Section 3.7. Some of the original plant piping has been left in place and has not been refurbished.

Restart

Restart

The staff was not satisfied with the aging management of the un-refurbished and left-in-place piping and components if a one time inspection or a ~~close~~ inspection does not identify any degradation at the time of restart. The staff argued that where layup programs were effective, one-time or other ~~startup~~ inspections performed during the extended outage when the system was and continues to be in a benign environment may not be adequate to detect degradation in the future when the system is returned to service and exposed to a different and potentially more aggressive environment. The applicant should explain how a one-time inspection or ~~startup~~ inspections performed during the Unit 1 extended outage are effective in detecting such future degradation, particularly in crevices. Alternatively, the applicant could commit to appropriate future periodic inspections in targeted locations for the aging effect. For portions of Unit 1 systems that have not been replaced, the applicant has not provided information to

restart

establish that there is sufficient operating history or sufficient data to conclude that one-time inspections are appropriate in lieu of periodic inspections.

The staff reviewed the applicant's subsequent responses (May 27, 2005 ~~and 31, 2005~~) and, in general, determined that the response is acceptable because the applicant included a commitment to perform periodic inspections of systems that were in a layup condition during the extended shutdown rather than relying on one-time or ~~startup~~ inspections and there is reasonable assurance that these periodic inspections will be capable of detecting degradation caused by potential latent aging effects, including crevice corrosion, when the systems are returned to service. However, the response did not include the plant specific periodic inspection program containing information required by NUREG-1800 Appendix A or the UFSAR supplement for staff review. The applicant is requested to clarify the scope and extent of the one-time inspections versus periodic inspections and identify the submittal date for this program and the UFSAR supplement as part of the application. The applicant agreed to provide a new program that performs periodic inspections to verify that no additional latent aging effects are occurring and correct degraded conditions prior to loss of function. The applicant provided a draft program description for new plant specific AMP B.2.1.42, "Unit 1 Periodic Inspection Program." This is to be formalized in a docketed correspondence. This is CI 3.0-3 LP.

CI 3.3.2.35-1: (Section 3.3 Bolting in Auxiliary Systems)

For auxiliary system closure bolting, the staff was concerned that cracking and loss of preload are not entirely addressed by either the American Society of Mechanical Engineers (ASME) Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program or Bolting Integrity Program. Although ASME Section XI requires bolt torquing loads to be in accordance with ASME Section III for replacement of Class 1 and 2 bolting, no bolt torquing requirements are specified for Class 3 bolting, NSR bolting or bolting that is reused after being removed for maintenance. The staff raised these issues in RAI 3.3.32.35-1.

The staff reviewed the applicant's response dated March 16, 2005, and found the response to be reasonable and acceptable. The applicant provided additional information to clarify that cracking and loss of preload in bolting are being effectively managed. However, the response did not provide the results of any self assessments, inspections or maintenance activities, and operating experience to determine if closure bolting in auxiliary systems was effectively managed at BFN for cracking and loss of preload. The staff discussed this issue with the applicant in a conference call and it was agreed that the verification of this will be a confirmatory item for the upcoming AMR inspection to be performed in September 2005. The applicant also agreed to include this in Appendix A Commitment Table. This is CI 3.3.2.35-1.

CI-B.2.1.36 (Section B.2.1.36, Structures Monitoring Program)

The staff had a follow up question in a May 4, 2005 conference call regarding evaluation of inspection personnel qualification based on industry Guidance American Concrete Institute (ACI) 349.3R-96 as stated in the Structures Monitoring Program. The staff stated that this industry guidance alone will not be adequate to qualify the inspectors for the examination of steel supports for the Structures Monitoring Program. The staff requested that the applicant reevaluate the program element from previous staff positions and submit the description for staff review. The applicant responded to the staff's question and committed to manage the aging effects of Class MC supports under ASME Code Section XI Subsection IWF. In its response to

SRP-LR Section 3.3.2.2.10 states that reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur in the neutron-absorbing sheets of the spent fuel storage rack in the spent fuel storage. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

The applicant stated that boral is used as a neutron absorbing material in the spent fuel pools. Reduction of neutron absorbing capacity and loss of material due to general corrosion could occur in the boral neutron absorbing material in spent fuel storage racks. The Chemistry Control Program manages general corrosion. ~~A one-time~~ inspection of boral coupon test specimens was performed that confirmed no significant aging degradation had occurred and the neutron absorbing capability of the boral had not been reduced. Reduction of neutron absorbing capacity and loss of material due to general corrosion will be managed by the Chemistry Control Program.

The staff reviewed the Chemistry Control Program and found that the program will adequately manage the effects of aging so that the intended functions will be maintained.

3.3.2.2.11 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.11 against the criteria in SRP-LR 3.3.2.2.11.

In LRA Section 3.3.2.2.11, the applicant addressed the further evaluation of programs to manage the potential for loss of material in buried piping of the service water and diesel fuel oil systems.

SRP-LR Section 3.3.2.2.11 states that loss of material due to general, pitting, and crevice corrosion and MIC could occur in the underground piping and fittings in the OCCW system and in the diesel fuel oil system. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

The applicant credited the Buried Piping and Tanks Inspection Program for managing loss of material for buried components of the service water and diesel fuel oil systems. This is consistent with GALL AMP XI.M34, "Buried Piping Inspection." The staff reviewed the applicant's operating history and found that the frequency of pipe excavation was sufficient to manage the effects of loss of material. The staff reviewed the Buried Piping Inspection Program and concluded that it is acceptable.

3.3.2.2.12 Evaluation of Auxiliary Systems AMRs That Reference Further Evaluations Not Included Under Auxiliary Sysyems

In the AMR for components in the auxiliary systems, the applicant referenced several further evaluations that are included under systems other than the auxiliary systems. These further evaluations were referenced based on applicability to the material, environment, and aging effect identified for components in the auxiliary systems. The staff reviewed these further

program number 35486. This leak is contained within the leak channel beneath the fuel pool liner). The fuel pool liners are monitored on a monthly basis per operation instruction 1-OI-78. The leak is small (~0.06 gpm)and has been steady over time without an increasing trend over the last ten years.

The staff found the above applicant's justification reasonable and adequate because it was supported by the fact that the operating history, structures monitoring baseline inspection, and results from the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for aluminum and stainless steel embedded or encased within concrete. Therefore, the staff's concerns described in RAI 3.4-10 are resolved.

RAI 3.5-14. The staff reviewed LRA Section 3.3.2.2 and LRA Table 3.3.1 with respect to the neutron-absorbing sheets in spent fuel storage racks. In LRA Section 3.3.2.2, the applicant stated that the Chemistry Control Program manages general corrosion and ~~a one-time~~ an inspection of Boral coupon test specimens was performed at BFN that confirmed that no significant aging degradation had occurred, and that the neutron-absorbing capacity of the Boral had not been reduced. Since it is implied that some Boral aging degradations had occurred at the time of inspection of the test specimens, in RAI 3.5-14, dated December 10, 2004, the staff requested the applicant to discuss the basis for the above assertion that the neutron-absorbing capacity of the Boral will be maintained at an adequate level during the extended period of plant operation.

In its response, by letter dated January 31, 2005, the applicant stated:

> A total of 16 boral coupons were placed in the Unit 3 spent fuel storage pool (SFSP) in October 1983. The coupons supplied by the rack manufacturer are of the same metallurgical condition as the high density fuel storage racks (HDFSR) in thickness, chemistry, finish, and temper. For the first six years of the planned fifteen year surveillance program, examination was to have taken place at two-year intervals. Accordingly, two coupons were removed in October 1985. Blisters were found upon examination, and because of this unexpected anomaly, three additional coupons were analyzed not finding any blisters. As a result of blisters found on the coupons removed in 1985, the surveillance program has been expanded to include monitoring the formation and behavior of these blisters. These boral coupons are periodically removed from the fuel pool for testing and are evaluated for corrosion or other degradation of the neutron absorber plates by comparing various physical characteristics of the test coupons to baseline measurements taken when the coupons were installed. Also, a metallurgical engineer examines the coupons for general corrosion, local pitting, and bonding. No further blisters, corrosion, or degradation has been identified in coupons evaluated through 2003.

The above response states that these Boral coupons are periodically removed from the fuel pool for testing and are evaluated for corrosion or other degradation of the neutron absorber plates by comparing various physical characteristics of the test coupons to baseline measurements taken when the coupons were installed. The response also implies that a metallurgical engineer periodically examines the coupons for general corrosion, local pitting, and bonding. Also, no further blisters, corrosion, or degradation have been identified in coupons evaluated through 2003; however, it was not clear to the staff whether these periodic inspections are ongoing activities that are an extension of the 1983 ~~One-Time Inspection.~~ Boral Coupon inspection program

~~Program~~ covering Boral coupon test specimens or a separate AMP in addition to the Chemistry Control Program mentioned above. The applicant was requested to clarify the key parameters of this periodic inspection program or activity including the objective, scope, frequency and inspection approach of the program.

In its response, dated May 24, 2005, the applicant stated that:

> The Boral coupon inspection program was initiated in 1983 to implement the inspection and testing requirements of UFSAR Section 10.3.6; this checks the long-term behavior of the material of the high density spent fuel racks. The inspection is performed per BFN Technical Instruction (TI) TI-116, "High Density Fuel Storage System Surveillance Program." When the TI is performed, Boral coupons are removed from the spent fuel storage pool and examined by the Metallurgical Engineer in their original condition to determine if sampling of surface corrosion products is appropriate. Thickness measurements are obtained of each coupon and documented in accordance with the TI. If degradation is such that further investigation is warranted, a minimum of one coupon is selected to be unsheathed or opened. Prior to the unsheathing process, a dye penetrant test for indications on the outer surfaces of the coupon will be performed and is examined by the Metallurgical Engineer. The Metallurgical Engineer decides if further unsheathing of the coupons is required. The visual examination by the Metallurgical Engineer is documented on the appropriate forms of the TI. The current frequency for performing this TI is two years. The surveillance frequency is re-evaluated each time the surveillance is performed and can be changed based on the trend of the historical data results. The inspection of the Boral coupons will continue until such time as the trend of the historical data results collected provides a basis to discontinue the inspections.

Based on its review, the staff found the applicant's response to RAI 3.5-14 acceptable. Therefore, the staff's concern described in RAI 3.5-14 is resolved.

RAI 4.7.4-1. LRA Table 3.5.2.2 lists the AMR results of expansion joint (elastomer, polyurethane foam) as a TLAA and refers the TLAA to LRA Section 4.7. LRA Section 4.7.4, "Radiation Degradation of Drywell Expansion Gap Foam," states that an analysis of the effect of dose on the foam showed the material properties will remain within the limits assumed by the original design analysis for the additional 20 years of extended operation. In RAI 4.7.4-1, dated December 10, 2004, the staff requested the applicant to provide a more detailed discussion of the analysis including a discussion of the assumptions adopted in the analysis, the type of data extrapolation applied, and the quantitative results obtained to justify the assertion that the requirements of 10 CFR 54.21(c)(1)(i) are fully met.

By letter dated January 31, 2005, the applicant provided its response to RAI 4.7.4-1. The staff evaluation of the applicant's response is provided in SER Section 4.7.4.

RAI 3.5-17. LRA Table 3.5.2.29, Radwaste Building, has three separate rows of component type listings (i.e., reinforced concrete, beams, column, walls, and slabs) which make references to note I,1 (last column of the table) and are shown to be associated with NUREG-1801 Section III.A3.1-h, Volume 2. Note I,1 of the table implies that the radwaste building is founded on rock or bearing piles. The note also refers to LRA Section 3.5.2.2.2.1 for further evaluation. Item 5 of the section does not clearly indicate that the radwaste building is founded on rock or bearing piles. In RAI 3.5-17, dated March 25, 2005, the staff requested the applicant to provide

used as a means to distinguish between sections of piping systems and components that have been replaced and those that have not been replaced. Although the response to RAI 3.0-9 LP identifies examples of piping systems and components that have been replaced, the staff is unable to identify specific components that have not been replaced that were subject to layup conditions. Further, the scope and results of sample inspections, including the sampling basis, have not been identified. To identify the scope and condition of components subject to Section XI or VIP inspections, the applicant was requested to identify the sampling basis and inspection results for piping systems and components subject to layup conditions that have not been replaced. The staff identified this as a URI. The staff discussed this issue with the applicant in follow-up conference calls. The following is a disposition of the resolution of the issues in the staff follow-ups, as documented in subsequent applicant submittals.

The applicant's response, by letter dated May 18, 2005, clarified its response to RAI 3.0-9 by stating that a large amount of piping in the drywell and reactor building had been replaced, but the majority of the piping had been inspected and determined to be acceptable without replacement. The applicant submitted a table to identify the UT examinations performed to demonstrate that the existing piping has wall thickness in excess of the manufacturer's minimum nominal wall thickness (>87.5 percent of nominal) and did not require replacement. The non-replaced piping inspected included the RHRSW, fire protection, emergency equipment cooling water (EECW), RCW, CRD, core spray, feedwater, HPCI, main steam, reactor core isolation cooling (RCIC), RHR, and RBCCW systems. The locations chosen for thickness examinations were susceptible areas that may have contained moisture during layup, or where engineering evaluation determined wear may have occurred. By letter dated May 27, 2005, the applicant submitted an additional clarification that the susceptible locations were those areas determined to have the highest potential for service-induced wear or latent aging effects, which includes all types of corrosion. The applicant also clarified that the inspection techniques utilized evaluate internal conditions and are sensitive to the presence of unacceptable conditions including wear, erosion, corrosion, including crevice corrosion if present.

The staff reviewed the applicant's response and found the response acceptable. The applicant clarified that, for piping not replaced that was in a layup condition during the extended outage, UT examinations had been performed at susceptible locations having the highest potential for service-induced wear or latent aging effects to demonstrate that adequate wall thickness exists. There is reasonable assurance that the UT inspection techniques applied are adequate to detect wear, erosion, and corrosion, including crevice corrosion. There is also reasonable assurance that the Corrective Action Program will continue to be applied to repair or replace degraded material identified in the inspections prior to adversely affecting the component intended function. Therefore, all issues related to the staff issue on replaced components are resolved.

3.7.1.3 Application of One-Time Inspection as Verification Program for Layup and Chemistry Control

The staff reviewed information presented in LRA Table 1 supplement dated February 19, 2004, on wet layup and determined that additional information was required. In RAI 3.0-2 LP, dated August 23, 2005, the staff requested the following additional information on Table 1 components in dry layup.

Add "INSERT" here.

INSERT

This section uses the term "One-Time Inspection" as the means of verifying the material condition of the system(s) of interest prior to restart. As described in the BFN RAI Response below, One-Time Inspections performed prior to restart are "restart inspections," and are included in the Unit 1 Restart Program. The following clarification as to the correct terms to be used (i.e., "Restart Inspections" and "Periodic Inspections") is provided here to preclude having to repeat this information every time the terms are clarified.

In a letter dated January 31, 2005, TVA responded to NRC questions concerning the aging of mechanical systems during the extended outage of BFN Unit 1. In the response to RAI 3.0-10 LP, TVA stated "… The inspections described in TVA's response to NRC Request for Additional Information Related to Aging of Mechanical Systems During The Extended Outage dated October 8, 2004 would have been better characterized as "restart" inspections instead of an AMP "One-Time Inspection."

In a letter dated May 27, 2005, TVA responded to NRC Proposed Unresolved Items 3.0-2 LP, 3.0-3 LP, and 3.0-4 LP. In that letter, TVA stated:

- The restart program and associated restart inspections are being implemented to return BFN Unit 1 to operation for the remainder of the current licensed operating period. The restart program does not take credit for lay-up in returning a system to operation and instead depends on inspections and/or replacement to ensure the components are satisfactory for the remainder of the current licensed operating period.
- BFN would implement targeted periodic inspections for Unit 1 systems that have been shutdown during the extended plant shutdown and that were not subsequently replaced as part of the Unit 1 restart project. These targeted periodic inspections will be performed after Unit 1 is returned to operation to verify aging management program effectiveness and to verify no additional latent aging effects are occurring. These periodic inspections are in addition to the restart inspections performed prior to Unit 1 restart.

The Unit 1 Periodic Inspection Program is described in LRA Section B.2.1.42.

For the systems covered by Table 1, the applicant stated that during layup, the systems were maintained in dehumidified air (60 percent relative humidity) and no additional aging effects were identified for the layup condition.

NRC Inspection Report 50-259/87-45 reported that in 1987 an acceptable program for monitoring the relative humidity of all pipe environments had not been finalized and the extent to which all parts of each system was being continually purged with dry air had not been established. For example, the standby liquid control system contained moisture in portions of the system and procedures did not require the system to be monitored for dryness. Although inadequacies in the program were later resolved, it appears that the moisture concerns existed for an extended period of time.

Also, industry documents such as EPRI NP-5106, "Sourcebook for Plant Lay-up and Equipment Preservation," revision 1, identify the need to monitor the effectiveness of the layup practices. This document states that relative humidity (RH) cannot be used alone as a layup surveillance technique to evaluate layup effectiveness.

Table 1 does not identify any additional inspections prior to restart to assess the condition of these systems, and it is not clear if inspections were performed in the layup condition. In light of the above inspection findings, the recommendations in the industry documents, and the possibility that parts of this system may not have been continually purged with dry air (such that the exact dryness of the surrounding air cannot be ascertained), discuss any inspections planned before startup to address the potential aging during the extended outage, and whether these inspections target system low points where condensate and/or chemicals could accumulate. If inspections have been performed recently, discuss the results of the inspections. If no inspections to verify the aging during the extended outage are planned, provide justification for not performing such inspections. Describe the process that was used to maintain equipment in a dry layup condition. Discuss how humidity was controlled and maintained below 60 percent, whether the 60 percent is relative to the coldest portion of the system, the results of any monitoring and trending of the air quality and humidity, and the corrective actions taken (including any inspections) for any conditions where the humidity criterion was exceeded (including corrective actions for the conditions identified in the above inspection report). Also, Table 1 identifies that future one-time inspections are planned. Discuss how the one-time inspections will differentiate between the rate of aging in the different environments (operation vs. shutdown), and discuss whether the one-time inspections will target locations that are susceptible to aging during normal operation or during shutdown.

In its response, by letter dated October 8, 2004, the applicant stated that, for components within the dry layup systems, a one-time inspection will be performed prior to restart to verify the material condition. The One-Time Inspection Program is described in LRA Section B.2.1.29. The applicant further stated that the One-Time Inspection Program does not differentiate between the rate of aging in different environments (for example, normal power operation versus cold shutdown).

In RAI 3.0-4 LP, dated August 23, 2004, the staff requested the following additional information for managing components exposed to a lubricating oil environment.

The response to RAI 3.0-10 LP by TVA letter dated January 31, 2005, clarified that this One-Time Inspection is actually a Restart Inspection.

In its response to RAI 3.0-5 LP, dated October 8, 2004, the applicant stated that Table 2 Systems [RVIs, Feedwater (03), Reactor Vessel Vents and Drains (10), Reactor Recirculation (68), Reactor Water Cleanup (69) and Control Rod Drive (85)] and Table 3 Systems [Condenser Circulating Water (27), Gland Seal Water (37), Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)] address the portions of these systems laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double valves was considered the same, (i.e., treated water or raw water) as water flowing through the valves prior to closure. N/A (not applicable) denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant further stated that during layup the temperature of the systems addressed in Tables 2 and 3 were less than 140 °F. Therefore, crack initiation and growth due to SCC is not a concern for stainless steels and nickel-based alloys in a wet layup environment.

The applicant clarified that the evaluation of these moist air environments for the systems addressed in Tables 2 and 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The LRA identified these trapped air environments for one-time inspection because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant stated that the one-time inspection described in the LRA will be performed prior to restart to verify the material condition. ←—See comment on p. 3-356.

In RAI 3.0-6 LP, dated August 23, 2004, the staff requested the following additional information on systems that were not part of the wet layup program and were exposed to stagnant treated (non-controlled) or raw water.

Table 3 of Evaluation of BFN Unit 1 Lay-up and Preservation Program (submittal dated February 19, 2004) identifies several systems that were not incorporated into the Unit 1 wet layup program. These systems were exposed to treated (non-controlled) or raw water during the extended outage. Table 3 concluded that there is no additional aging management for these systems. The staff required additional information on the following: (1) discussion of the results of any water samples, including pH, oxygen levels, aggressive chemical species, biological activity, and corrosion product levels, (2) discussion whether the systems were stagnant or periodically flowed, (3) discussion whether the plans for prestartup inspections to determine the loss of material due to general, pitting, and crevice corrosion, MIC, dealloying, and galvanic corrosion, or provide justification that such inspections are not needed, and (4) also, discuss inspections for the degradation of other materials, such as elastomers and other non-metallic materials.

In its response to RAI 3.0-6 LP, dated October 8, 2004, the applicant stated:

> Condenser Circulating Water System (27) - System 27 was exposed to Tennessee River water which is the same environment it is exposed to during normal operation. Without the addition of foreign chemicals the aging effects during normal operation and during layup are the same.

Gland Seal Water System (37) - The system was drained (ambient air present) with the gland seal tank in component layup per AMPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system were not completely drained. The applicant stated that therefore, stagnant treated water supplied from the condensate system was evaluated for these areas.

Systems (Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75) - The torus and torus attached piping for System 64 (i.e., the torus itself) and for Systems 71, 73, and 75 (torus attached piping) saw torus water maintained by Chemistry Program CI-3.1, Appendix A, Table 20) for extended periods of time until the torus was drained in the summer of 2003. When filled, the torus is approximately half full of water with the other half ambient air. The torus water was not "flowing" in that the only significant water movement was relatively infrequent transfers into and out of the Unit 1 torus. The torus on an operating unit cannot be considered "flowing" either. The operating unit's torus would also be nitrogen-inerted. Torus coating touch-up/repair is part of the restart work to be completed while the torus is drained. The torus impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. S/cm, 75 ppb, and 75 ppb, respectively. The applicant stated that a review of sampling data showed that the torus water was maintained within the chemistry specifications and that sampling is performed quarterly.

The One-Time Inspection described in the license renewal application will be performed prior to restart to verify the material condition. See comment on p 3-356.

In RAI 3.0-7 LP, dated August 23, 2004, the staff requested the following additional information on Notes 1 and 2 of Tables 2 and 4 concerning inspections to be performed prior to the Unit 1 restart.

Notes 1 and 2 of Tables 2 and 4 indicate that inspections will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended shutdown. Examples include additional aging effects for copper alloy, cast iron, cast iron alloy, and stainless steel components in system locations where condensation could build up, and carbon and low-alloy steel in an internal environment. No descriptions of the inspections were provided. The staff asked the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections.

The applicant responded to RAI 3.0-7 LP by stating that Note 1 of Tables 2 and 4 identifies the potential for external general corrosion on carbon and low-alloy steel components that are normally operated at temperatures greater than 212 °F. This note is applicable to the reactor vessel (rv), feedwater system (03), and the heater vents and drains system (06). External surface monitoring is performed in accordance with the Systems Monitoring Program described in the LRA Section B.2.1.39. The applicant stated that this is the same AMP proposed for managing external loss of material during the period of extended operation.

The applicant also stated that Note 2 of Tables 2 and 4 identifies the potential for internal loss of material and cracking (aluminum only) that are normally exposed to either dry air or nitrogen. The applicant clarified that this note is applicable to the following systems and materials:

In the response to RAI 3.0-9 LP, the applicant did submit specific information on inspections for piping systems not initially identified for replacement. The applicant identified that specific piping systems had wall thickness measurements taken on a sample basis with locations chosen that were most susceptible to degradation. The recorded wall thickness measurements were reviewed with respect to the Code-required minimum wall thickness including a 40-year corrosion allowance. The applicant also identified specific examples of inspections for various systems and components, but the response did not entirely resolve the staff's concerns.

For those layup programs considered to be effective, one-time or other ~~startup~~ restart inspections performed during the extended outage when the system is in a benign environment, may not be adequate to detect degradation in the future when the system is returned to service and exposed to a different and potentially more aggressive environment. The applicant was requested to explain how a one-time inspection or ~~startup~~ restart inspections performed during the Unit 1 extended outage, will be effective in detecting such future degradation, particularly in crevices. Alternatively, the applicant could commit to appropriate future periodic inspections in targeted locations for the aging effect. For portions of Unit 1 systems that have not been replaced, the applicant has not provided information to establish that there is sufficient operating history or sufficient data to conclude that one-time inspections are appropriate in lieu of periodic inspections. For example, carbon and low-alloy steel materials that are subject to one-time inspections may show no signs of degradation as the result of effective layup programs, but will experience aging effects that will go undetected when returned to service. The applicant was requested to provide additional information to establish if there is sufficient data to conclude that one-time inspections are appropriate to manage future aging effects for Unit 1 systems exposed to layup conditions.

In response to RAI 3.0-9 LP, in its submittal dated January 31, 2005, the applicant identified the Unit 2 and 3 lessons learned to determine system integrity for certain systems. If the applicant is crediting operating experience from Units 2 and 3, the applicant was requested to justify how that experience, including inspection results, is applicable to Unit 1. Alternatively, the applicant may commit to appropriate targeted periodic inspections. The applicant was requested to explain how Unit 1 one-time inspection and restart inspections performed prior to startup are adequate to detect future degradation, especially in crevices, when the system is returned to service. For example, in Table 3, the One-Time Inspection Program is credited with managing the condenser circulating water system for loss of material in a raw water environment. One-time inspection may not be appropriate to manage loss of material in a raw water environment where degradation was expected. If the applicant is crediting operating experience from Units 2 and 3, the applicant was requested to justify how that experience, including inspection results, is applicable to Unit 1. Alternatively, the applicant could commit to appropriate targeted periodic inspections. The staff identified this as an unresolved issue (reference applicant's letter dated May 27, 2005, URI 3.0-2 LP).

Industry documents such as EPRI NP-5106, Rev. 1, "Sourcebook for Plant and Equipment Preservation," caution that the effects of a bad layup may result in significant contaminants that remain in crevices causing degradation once the system is returned to service. Crevices exist in the RPV internals as well as in piping systems. For example, in Table 3, the One-Time Inspection Program is credited with managing the condenser circulating water system for loss of material in a raw water environment. One-time inspection may not be appropriate to manage loss of material in a raw water environment where degradation is expected. If the applicant is crediting operating experience from Units 2 and 3, the applicant was requested to justify how

that experience, including inspection results, is applicable to Unit 1. Alternatively, the applicant could commit to appropriate targeted periodic inspections. In a follow-up teleconference on March 29, 2005, the staff originally proposed this as an unresolved issue (URI 3.0-3 LP). The staff discussed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow ups and subsequent applicant submittals.

The applicant's response to these staff concerns, (URIs 3.0-2 LP and 3.0-3 LP by letter dated May 27, 2005) clarified that the applicant will implement targeted periodic inspections for Unit 1 systems that have been shut down during the extended plant shutdown. The applicant clarified that restart inspections are being implemented and the restart program does not take credit for layup inspections and/or replacement to ensure the components are satisfactory for the remainder of the current operating period. The applicant clarified that the targeted periodic inspection techniques evaluate internal conditions that are sensitive to the presence of wear, erosion, and corrosion (including crevice corrosion). The applicant further clarified that the same AMPs applied to Units 2 and 3 will be applied to Unit 1 and, for Unit 1, the applicant committed to targeted periodic inspections to assess the effectiveness of the AMPs and to identify if latent aging effects were present as a result of the extended outage. These periodic inspections are in addition to the restart inspections and the restart inspections can be utilized as baseline for comparison. Additional periodic inspections are to be performed on ESF and auxiliary systems or portions of systems containing air/gas, treated water or raw water that were in a layup condition during the extended outage. The first periodic inspection will be performed prior to the end of the current operating period and the frequency of the periodic inspections will be determined based on the outcome of the first periodic inspections performed. The scope and extent of periodic inspections will be similar to the One-Time Inspection Program and will be developed prior to the period of extended operation.

In the May 27, 2005, response, the applicant further clarified an earlier response that the condenser circulating water system raw water environment identified in the application is actually an air environment and the One-Time Inspection Program is not used as an AMP for any of the Unit 1 shutdown raw water systems.

The staff reviewed the applicant's subsequent responses (May 27, 2005 and 31, 2005) and, in general, determined that the response is acceptable because the applicant included a commitment to perform periodic inspections of systems that were in a layup condition during the extended shutdown rather than relying on one-time or ~~startup~~ restart inspections and there is reasonable assurance that these periodic inspections will be capable of detecting degradation caused by potential latent aging effects, including crevice corrosion, when the systems are returned to service. However, the response did not include the plant specific periodic inspection program containing information required by NUREG-1800 Appendix A or the UFSAR supplement for staff review. The applicant is requested to clarify the scope and extent of the one-time inspections versus periodic inspections and identify the submittal date for this program and the UFSAR supplement as part of the application. The applicant agreed to provide a new program that performs periodic inspections to verify that no additional latent aging effects are occurring and correct degraded conditions prior to loss of function. The applicant provided a draft program description for new plant specific AMP B.2.1.42, "Unit 1 Periodic Inspection Program." This will be provided in a docketed correspondence. This is CI 3.0-3 LP.

aggressive than their counterparts in the plant operating environments, and the aging effects for these components in the normal operating and layup environments are the same. RAI 3.2-1 LP is, therefore, resolved.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, May 27, and May 31, 2005, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the HPCI system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 HPCI system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 1 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the HPCI system.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

As stated in Table 1 of the February 19, 2004, submittal, for the HPCI system (73) and core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) environments are subject to general corrosion during the period of extended outage. For the LRA AMR, the same aging effect is identified for the same components in an air/gas (internal) environment, with the One-Time Inspection Program credited as the only AMP for managing the identified aging effects. No additional AMPs were proposed for the layup program.

In RAI 3.2-2 LP, the staff requested the applicant to provide justification that additional inspection programs were not required, for possible unintended moisture conditions accumulated in the above components of both the HPCI system (73) and the core spray system (75), during the period of extended outage. By letter dated October 8, 2004, the applicant stated that pooled water is not anticipated for the portions of Systems 73 and 75 addressed in Table 1 per the layup program 0-TI-373. To ensure detection of possible material degradation, the applicant stated that the One-Time Inspection Program described in the LRA will be performed prior to the Unit 1 restart, instead of being performed at the end of the current licensing period, to verify that the layup program had been adequate in protecting the material from significant degradation. Based on the lack of aggressive environments associated with the components in Systems 73 and 75, the staff found the applicant's initiative in performing a one-time inspection for possible material degradation prior to Unit 1 restart is acceptable. RAI 3.2-2 LP is, therefore, resolved.

(See Comment on p. 3-356)

For the Unit 1 containment system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion. Carbon and low-alloy steel components in buried (external) environments are subject to loss of material due to general, crevice, and pitting corrosion, and MIC. Stainless steel components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Elastomer components in inside air (external) and outside air (external) environments are subject to hardening and loss of strength due to elastomer degradation (ultraviolet radiation).

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates components in the containment system (64), HPCI system (73), and core spray system (75) that are exposed to an air/gas (internal) environment during normal operation, whereas their counterpart environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of these systems may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in these systems, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. By letter dated October 8, 2004, the applicant stated that Table 3 addresses the aging management for portions of several systems (including containment, HPCI, and core spray systems) laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double isolation valves was considered the same (i.e., raw or treated water) as was water flowing through the valves prior to closure. The applicant stated that the N/A denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant stated that the evaluation of these moist air environments for the systems addressed in Table 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The applicant stated that the LRA identified these trapped air environments for one-time inspections because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant further stated that the one-time inspection will be performed prior to restart, ~~instead of being performed prior to the end of the current licensing period,~~ to verify the material condition.

(See comment on p. 3-356.)

The staff determined that the applicant had adequately explained the nature of the trapped air/gas environments, and why the evaluation of the aging effects for the treated-water environment, in the above three ESF systems, would encompass that of the aging effects for a moist air environment in these systems. The applicant also committed to perform inspections in

(See comment on p. 3-356.)

accordance with the LRA One-Time Inspection Program, prior to Unit 1 restart, to verify the material condition of the system components. This is acceptable to the staff, and RAI 3.0-5 LP is closed for Systems 64, 73, and 75.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment system.

- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29).
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the containment (64), HPCI (73), and core spray (75) systems were exposed to treated (non-controlled) water environments during the extended outage. Table 3 identified no additional AMPs for these layup systems, other than those AMPs specified in LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing the results of any water sampling performed, and discuss whether the systems were stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. By letter dated October 8, 2004, the applicant stated that the torus and torus attached piping for the containment system (i.e., the torus itself) and HPCI and core spray systems (torus attached piping) saw torus water maintained by CI-13.1 chemistry program, Appendix A, Table 20, for extended periods of time until the torus was drained in the summer of 2003. When filled, the torus is approximately half full of water with the other half ambient air. The torus water was not flowing in that the only significant water movement was relatively infrequent transfers into and out of the Unit 1 torus. The torus on an operating unit can not be considered "flowing" either. The operating unit's torus would also be nitrogen-inerted. The applicant stated that torus coating touch-up/repair is part of the restart work to be completed while the torus is drained.

The applicant stated that the torus impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. S/cm, 75 ppb, and 75 ppb, respectively, which are within the chemistry specifications. Sampling is performed quarterly. The applicant also stated that the LRA One-Time Inspection will be performed prior to Unit 1 restart to verify the material condition.

(See comment on p. 3-356)

Based on the above information, pending the staff's acceptance of the applicant's wet layup program chemistry controls provided in SER Section 3.7.1.1, the staff determined that the applicant adequately addressed the staff's concerns related to water chemistry existing during layup and pre-startup inspections, for the containment, HPCI, and core spray systems. RAI 3.0-6 LP is, therefore, closed for these three systems.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.2.2 High Pressure Coolant Injection System

Technical Staff Evaluation. The technical staff reviewed the AMR of the HPCI system (73) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The HPCI system is described in LRA Section 2.3.2.3. LRA Table 3.2.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that the Unit 1 HPCI system within the scope of license renewal was not incorporated into the layup program but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the HPCI system (73) saw treated (torus) water maintained by CI-13.1 chemistry program for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the applicant's February 19, 2004, submittal provides the AMR of the HPCI system components within the scope of license renewal that were not incorporated into the wet layup program. The component types include bolting, condenser, expansion joint,

identification of AERMs, and proposed aging management. Also, discuss any inspections that are planned to determine the extent of aging during the extended outage.

By letter dated October 8, 2004, the applicant responded to RAI 3.3-1 LP by providing the following additional information.

With regard to residual heat removal service water system (23) and emergency equipment cooling water system (67), the applicant stated that the Unit 1 portions of piping and components for these systems not required for Unit 2 and 3 operation are not in the layup program. The piping and components in these systems are in shared systems and contained either raw water or moist air during the extended outage period. The applicant stated that these systems have been evaluated for a raw water and/or moist air environment for the in-service portions of these systems. The aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The One-Time Inspection described in the license renewal application will be performed prior to Unit 1 restart to verify the material condition.

The applicant also stated that for control air system (32) the Unit 1 piping components of this system not required for Unit 2 and 3 operation but in scope for license renewal is not in the layup program. For this system, any additional aging effects would be due to moisture collecting in the system components. For the operating condition the internal environment is air/gas without a significant amount of moisture present. During layup there were no moisture controls on the non-operating Unit 1 portions of this system. Without moisture controls the possibility of moisture collecting at system low points exists. The aging effects associated with moist air are contained in the detailed layup evaluation of the containment inerting system (76) and the containment atmosphere dilution system (84). The potential aging effects for the control air will be similar to those identified for the containment inerting and containment atmosphere dilution systems. The One-Time Inspection described in the license renewal application will be performed prior to Unit 1 restart to verify the material condition.

(See comment on p. 3-356.)

For the sampling and water quality system (43), the applicant stated that the Unit 1 piping and components of this system not required for Unit 2 and 3 operation are not in the lay-up program. The piping and components in this system contained treated water, raw water, and/or moist air during the extended outage period. This system has been evaluated for these environments for the operating condition. The aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The One-Time Inspection described in the license renewal application will be performed prior to Unit 1 restart to verify the material condition. Related to the reactor water cleanup system (69), the applicant stated that the system was evaluated per BFN Unit 1, Layup and Preservation Program, Table 2.

For the reactor building closed cooling water system (70) the applicant stated that portions of the Unit 1 piping and components of this system not required for Unit 2 and 3 operation are not in the layup program. The piping and components in this system contained treated water maintained to CI-13.1 and/or moist air during the extended outage period. The aging effects associated with treated water maintained to CI-13.1 are contained in the detailed layup evaluation of the reactor core isolation cooling system (71), the HPCI system (73), and the core spray system (75). The potential aging effects for the closed cooling water system (70) will be similar to those identified for the reactor core isolation cooling system (71), the hpci system (73), and the core spray system (75). The One-Time Inspection Program described in the LRA will be performed prior to Unit 1 restart to verify the material condition.

For the radioactive waste treatment system (77), the applicant stated that the Unit 1 piping and components for this system are not in the layup program. The piping and components in this system within the LRA scope remained in-service. An aging effects evaluation was performed for this system and documented in LRA Table 3.3.2.25.

Finally, related to the neutron monitoring system (92), the applicant stated that the Unit 1 portions of piping and components for this system are not in the layup program. The portion of this system that is within the scope of license renewal is part of the reactor vessel pressure boundary. An aging effects evaluation was performed for the Unit 1 layup portions of the RVI system. The aging effects evaluation for the RV and RVI encompasses the neutron monitoring system (92). The One-Time Inspection Program described in the LRA will be performed prior to Unit 1 restart to verify the material condition. See Comment on p. 3-356.

With the staff issue raised in RAI 3.0-5 LP concerning MIC in stagnant areas, the staff reviewed the applicant's response to RAI 3.3-1 and, in general, found it to be reasonable and acceptable because it clarified that the subject systems were either in-service or were not part of the layup program. Systems that were in service during the extended outage are reviewed as part of the AMR. For systems that were not part of the layup program, the applicant includes an evaluation of aging effects and credits one-time inspections to verify the material condition. In these systems, the applicant's evaluation of aging effects determined that aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The staff's evaluation of one-time inspections to manage aging effects including MIC for stagnant systems not in-service can be found in SER Sections 3.7.1.3.1.1 and 3.7.1.4 pertaining to the applicant's response to RAI 3.0-9 LP and RAI 3.0-10 LP.

3.7.5 Steam and Power Conversion Systems

3.7.5.1 Steam and Power Conversion Systems in Wet Layup

3.7.5.1.1 Feedwater System

Technical Staff Evaluation. The technical staff reviewed the AMR of the feedwater system (03) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The feedwater system is described in LRA Section 2.3.4.3. LRA Table 3.4.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 feedwater system was maintained in wet layup during the extended shutdown. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 2 of the applicant's February 19, 2004, submittal provides the AMR of the feedwater system components within the scope of license renewal that were maintained in wet layup conditions. The component types include bolting, fittings, piping, restricting orifices, tubing, and valves.

(See Comment on p. 3-356)

The applicant stated that the evaluation of these moist air environments for the systems addressed in Table 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The applicant stated that the LRA identified these trapped air environments for one-time inspections because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant further stated that the one-time inspection will be performed prior to restart, ~~instead of being performed prior to the end of the current licensing period~~, to verify the material condition.

The staff determined that the applicant adequately explained the nature of the trapped air/gas environments, and why the evaluation of the aging effects for the raw and treated-water environments, in the above two systems, would encompass that of the aging effects for a moist air environment in these systems. The applicant also committed to perform inspections in accordance with the LRA One-Time Inspection Program, prior to Unit 1 restart, to verify the material condition of the system components. This is acceptable to the staff, and RAI 3.0-5 LP is closed for the condenser circulation water system (27) and gland seal water system (37) systems. The staff's discussion of the general adequacy of the One-Time Inspection Program for systems containing treated water and raw water during layup is provided in SER Sections 3.7.1.3.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004 and January 31, May 27, and 31, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the condenser circulation water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 condenser circulation water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 identifies the following AMPs for managing the aging effects described above for the condenser circulating water system.

- One-Time Inspection Program (B.2.1.29)
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant identified no additional AMPs for the components in this layup system, other than the above AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the conclusion by discussing the water samples performed for the normal operation and the period of extended

outage. By letter dated October 8, 2004, the applicant stated that the condenser circulation water system was exposed to Tennessee River water, which is the same environment as it is exposed to during normal operation. Without the addition of foreign chemicals the aging effects during normal operation and during layup are the same. However, the applicant stated that the one-time inspection described in LRA will be performed prior to restart to verify the material condition. This commitment is acceptable to the staff, and RAI 3.0-6 LP is closed for the condenser circulation water system. The staff's discussion of the general adequacy of the One-Time Inspection Program as it relates to the systems containing raw water during layup is provided in SER Section 3.7.1.3.1. (See Comment on p. 3-356.)

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 27 and 31, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 condenser circulation water system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 condenser circulation water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.2.2. Gland Seal Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the gland seal water system (37) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The gland seal water system is described in LRA Section 2.3.4.7. LRA Table 3.4.2.7 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the portion of the Unit 1 gland seal water system within the scope of BFN license renewal was not incorporated into the BFN wet layup program, but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of BFN license renewal for the gland seal water system (37) saw treated water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the February 19, 2004, submittal provides the AMR of the gland seal water system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, fittings, piping, tanks, tubing, and valves.

chemistry program implemented during the wet layup period is essentially the same program that BFN uses on the two operating units during Cold Shutdown conditions for refueling and maintenance outage. This extended operation program would consist of CI-13.1 "Chemistry Program" controls which would continue to be based on the EPRI BWR Water Chemistry Guidelines (TR-103515).

3. As discussed in Item (1), the treated water is sampled and monitored per the Chemistry Control Program CI-13.1. The aging effects/aging mechanisms for the components within the systems in layup are similar to those determined for the operational units.

4. As discussed in Item (1), the possibility of low flow or stagnant conditions exists in this system. Due to low flow conditions in the system, the One-Time Inspection described in the license renewal application will be performed prior to restart to verify the material condition.

5. There have been no latent effects identified for the chemistry program implemented during the Unit 1 wet layup period. This program is essentially the same program that BFN uses for operating units during Cold Shutdown conditions for refueling and maintenance outages (EPRI BWR Water Chemistry Guidelines TR-103515-R2).

6. The One-Time Inspection Program will be implemented prior to restart. See Comment on p. 3-356.

Based on the above responses to the RAI, the staff considered that the applicant had adequately addressed its concerns, and ensured that the wet layup components in the system had not been subjected to aging degradation more severe than their Units 2 and 3 counterparts during plant operation. RAI 3.4-1 LP is, therefore, closed for the gland seal water system. The staff's discussion for the general adequacy of the One-Time Inspection Program as a verification program for layup and chemistry control is provided in SER Section 3.7.1.3.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the gland seal water system (37) are exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.5.2.1.

Table 3 of the applicant's February 19, 2004, submittal indicates that, for gland seal water system (37), copper-alloy components and cast iron and cast iron alloy components saw treated (condensate) water for an extended period of time. The applicant identified loss of material due to general corrosion, selective leaching, crevice corrosion, and pitting corrosion as the AERMSa. In RAI 3.4-4 LP, the staff requested the applicant to explain why galvanic corrosion is not identified as a potential aging mechanism for the components. By letter dated October 8, 2004, the applicant stated that the cast iron components within the gland seal water system (37) are in contact with carbon steel piping. Cast iron and carbon steel are grouped together in the galvanic series as similar metals. Since cast iron components within the system are not in

contact with more cathodic materials, galvanic corrosion is not a concern. Similarly, copper-alloy components are not in contact with a more cathodic material such as stainless steel within the gland seal water system. Therefore, galvanic corrosion is not a concern. The staff found the applicant's explanation to be acceptable, and RAI 3.4-4 LP is closed.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 27 and 31, 2005, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the gland seal water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 gland seal water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the gland seal water system.

- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the gland seal water system (37) were exposed to treated (non-controlled) water environments during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by discussing the water sampling performed for the normal operation and the period of extended outage. By letter dated October 8, 2004, the applicant stated that the system had been drained (ambient air present) with gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system had not been completely drained. Therefore, stagnant treated water supplied from the condensate system (02) was evaluated for these areas. The applicant stated that the One-Time Inspection Program described in the LRA will be performed prior to restart to verify the material condition. The staff found the applicant's commitment to perform a one-time inspection for the potential low points in the system to be acceptable, and RAI 3.0-6 LP is closed for the gland seal water system. The staff's discussion of the general adequacy of the One-Time Inspection Program in managing the identified aging effects for the system components, as opposed to periodic inspections, is provided in SER Section 3.7.1.3.1.

(See comment on p. 3-356.)

inspections. By letter dated October 8, 2004, the applicant stated that internal surface monitoring is performed in accordance with the One-Time Inspection Program described in the LRA Section B.2.1.29. The applicant noted that this is the same AMP proposed for managing internal aging effects of components exposed to moist air during the period of extended operation. The staff found the applicant's commitment to perform one-time inspections prior to restart to be acceptable, and RAI 3.0-7 LP is closed for the main steam system. The staff's discussion of the general adequacy of the One-Time Inspection Program in managing the identified aging effects, as opposed to periodic inspections of the system components is provided in SER Section 3.7.1.3.1. (See comment on p. 3-356.)

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 27 and 31, 2005, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 main steam system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 main steam system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.3.2 Condensate and Demineralized Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the condensate and demineralized water system (02) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The condensate and demineralized water system is described in LRA Section 2.3.4.2. LRA Table 3.4.2.2 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that portions of Unit 1 condensate and demineralized water system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal lacked moisture controls and is, therefore, considered moist air. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004 submittal; provides the AMR of the condensate and demineralized water system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, condenser, expansion joint, fittings, piping, pumps, restricting orifices, tanks, tubing, and valves. In its submittal, the applicant. identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air and outside air.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the condensate system and demineralized water system.

- Chemistry Control Program (B.2.1.5)
- Aboveground Carbon Steel Tanks Program (B.2.1.26)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.6, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the condensate and demineralized water system (02), no AMPs other than those identified above for the period of extended operation are noted for the extended outage. In RAI 3.4-5 LP, the staff requested the applicant to justify the basis for not performing inspections of the affected system components prior to restart. By letter dated October 8, 2004, the applicant stated that the one-time nspection described in the LRA will be performed prior to restart to verify the material condition. The staff found the applicant's commitment of performing one-time inspections prior to restart to be acceptable, and considers RAI 3.4-5 LP closed for this system. The staff's discussion of the general adequacy of the One-Time Inspection Program as opposed it periodic inspections for the system components is provided in SER Section 3.7.1.3.1. (See Comment on p. 3-356.)

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, and January 31, May 27, and May 31, 2005, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 condensate and demineralized water system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 condensate and demineralized water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

Feedwater (03)	Copper Alloy
Main Steam (01)	Aluminum Alloy
Containment Inerting (76)	Carbon and Low-alloy steel Stainless Steel Nickel Alloy Copper Alloy Aluminum Alloy Cast Iron
Containment Atmosphere Dilution (84)	Carbon and Low-alloy steel Stainless Steel Copper Alloy Aluminum Alloy Cast Iron

Finally, the applicant stated that internal surface monitoring is performed in accordance with the One-Time Inspection Program described in the LRA Section B.2.1.29. This is the same AMP proposed for managing internal aging effects of components exposed to moist air during the period of extended operation.

In RAI 3.0-8 LP, dated August 23, 2004, the staff requested the following additional information on management of galvanic corrosion with the water chemistry and one-time inspections.

The LRA and the supplement dated February 19, 2004, are not clear regarding the management of galvanic corrosion. There is the potential for galvanic corrosion during the extended outage for those systems that were maintained in wet layup, wet non-layup, or moist air such that condensation and pooling could occur. The LRA and Reference 2 state that galvanic corrosion is managed through use of the Chemistry Control Program and the One-Time Inspection Program; however, there were differences in water chemistry during the extended outage and the One-Time Inspection Program does not cover galvanic corrosion. The applicant was requested to describe how galvanic corrosion during the extended outage is managed. The applicant was also requested to discuss any inspections that are planned to determine the extent of galvanic corrosion during the extended outage.

In its response to RAI 3.0-8 LP, dated October 8, 2004, the applicant stated that the Chemistry Control Program implemented during the extended outage is the same program that BFN uses on the two operating units during cold shutdown conditions for refueling and maintenance outages. This extended outage program would consist of CI-13.1 chemistry program controls, which would continue to be based on the EPRI BWR Water Chemistry Guidelines (TR-103515). The applicant further stated that the One-Time Inspection Program utilized to verify the effectiveness of the Chemistry Control Program for preventing loss of material will select the susceptible locations (where materials with different electrochemical potentials are in contact in the presence of contaminants). Finally the applicant stated that galvanic corrosion is included in the One-Time Inspection Program.

In regard to SCC, the staff found the applicant's response to RAI 3.0-5 LP to be reasonable and acceptable, because the applicant clarified that during layup the temperature of the systems

The response to RAIs 3.0-2 LP, 3.0-3 LP, and 3.0-4 LP by TVA letter dated May 27, 2005, clarified that this One-Time Inspection is actually a Periodic Inspection.

(See Comment on p. 3-360.)

Program to effectively manage aging effects for a plant that has been in an extended outage, the following information was requested in RAI 3.0-10 LP.

3.7.1.3.1 Application of One-time Inspection Versus Periodic Inspections

Unless there is sufficient data, one-time inspections may not be appropriate where degradation is expected to occur or not occur very slowly. For systems not associated with the BWRVIP Program, the applicant was requested to justify why a one-time inspection is appropriate for aging management in lieu of periodic inspections. If the applicant is crediting previous inspections performed during the extended outage, the applicant should clarify the extent and results of those inspections. If the one-time inspection is intended to represent a baseline, and additional inspections will be applied to evaluate future degradation, the applicant should so clarify and explain how follow-up inspections will be performed, including information to support the effectiveness of the corrective action process to resolve aging degradation.

GALL AMP XI.M32 indicates that one-time inspections, or any other action or program, is to be reviewed by staff on a plant-specific basis. If the new One-Time Inspection Program is not available at this time for review, the staff cannot make a judgment as to the adequacy of the program to effectively manage aging effects during the extended outage or for the period of extended operation. Although the applicant credits the One-Time Inspection Program as being consistent with the GALL Report, sufficient information is not included to determine acceptability from a plant-specific basis. The applicant was requested by letter dated December 16, 2004, to submit additional information on each element of the One-Time Inspection Program to support a plant-specific review by staff. Alternatively, the applicant was requested to submit a plan to submit the program for staff review and a plan to implement the program with sufficient time to validate its effectiveness. Since this program is to be implemented prior to start-up, the program should be readily available now or in the near future. Specific information to be submitted relevant to the staff review of one-time inspections planned prior to start up should include:

Scope of Program - The applicant was requested to identify specific components and locations subject to one-time inspection or clarify the basis for selecting a particular sample size. This concern is addressed in greater detail below.

Parameters Monitored/Inspected - The applicant was requested to identify specific parameters monitored/inspected such as wall thinning, general corrosion, cracking, pitting, erosion, MIC, and fouling

Detection of Aging Effects - The applicant was requested to identify NDE techniques applied to detect degradation and clarify which components will be inspected internally. Identify qualifications of inspection personnel and any specific training to improve techniques where results are subjective or qualitative.

Monitoring and Trending - The applicant was requested to clarify how plant-specific and industry-wide experience will be applied to the techniques used to perform follow-up inspections.

Acceptance Criteria - The applicant was requested to define general acceptance criteria with justification (e.g., no evidence of any degradation or minimum wall thickness

ENCLOSURE 8

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

CORRECTION OF ERROR IN TVA LETTER TO NRC
DATED JANUARY 31, 2005

(SEE ATTACHED)

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

CORRECTION OF ERROR IN TVA LETTER TO NRC
DATED JANUARY 31, 2005

By letter dated December 31, 2003, TVA submitted, for NRC review, an application pursuant to 10 CFR 54, to renew the operating licenses for the Browns Ferry Nuclear Plant, Units 1, 2, and 3.

TVA's January 31, 2005, letter to the NRC replied to NRC Requests for Additional Information for Reactor Vessel and Internals Mechanical Systems Sections 3.1, 4.2, and B.2.1. On page E-55, the second paragraph of TVA's response to RAI 4.2.4-1(A) stated: "The following is appended to the disposition statement of LRA Section 4.2.2.5 …"

This paragraph should have stated: "The following is appended to the disposition statement of LRA Section 4.2.4 …"

ENCLOSURE 9

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT (BFN)
UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION (LRA)

LIST OF COMMITMENTS MADE IN THIS RESPONSE

The following commitments were made in this letter:

1. For Unit 1, TVA will perform one time confirmatory UT measurements on the vertical cylindrical area immediately below the drywell flange. These UT measurements will be obtained prior to restart of the unit.

2. TVA will perform one time confirmatory ultrasonic thickness (UT) measurements on a portion of the cylindrical section of the drywell in a region where the liner plate is 0.75 inches thick. These UT measurements will be obtained on Unit 2 and Unit 3 prior to their period of extended operation.

3. TVA will perform a BFN plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand normal, upset, emergency, and faulted loads, as applicable, considering the effects of stress relaxation until the end of the period of extended operation. TVA will take appropriate corrective action if the above plant-specific analysis does not satisfy the specified criteria.

4. TVA will submit the analysis or the corrective action taken to resolve the core plate hold-down bolt issue to the NRC for review 2 years prior to the period of extended operation.

5. TVA will perform a confirmatory inspection of the RHRSW pump pit supply piping using underwater cameras or other methods or techniques available at the time of the inspection. The inspection will include internal portions of one RHRSW pump pit supply pipe, and to the extent possible, will identify flow restrictions and material loss due to corrosion. The inspection will be performed from either the CCW Pump Pit or the RHRSW Pump Pit end of the pipe. This inspection will be performed prior to the period of extended operation.

6. TVA will include instructions in the CCW pump pit Preventive Maintenance Program to periodically inspect the sluice gate valves. This will be completed prior to the period of extended operation.

7. TVA will perform a confirmatory inspection of the seismic restraints in the RHRSW pump pit. This inspection will be performed prior to the period of extended operation.