Safety Evaluation Report

Related to the License Renewal of the Fort Calhoun Station, Unit 1

Docket No. 50-285

Omaha Public Power District

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

September 2003

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Fort Calhoun Station, Unit No. 1 (FCS), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (staff). By letters dated January 9 and April 5, 2002, Omaha Public Power District (OPPD or the applicant) submitted the LRA for FCS in accordance with Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54 or the Rule). OPPD is requesting renewal of the operating license for Unit 1 (license numbers DPR-40) for a period of 20 years beyond the current expiration of midnight, August 9, 2013.

The FCS site is located in Washington County, NE, on the west bank of the Missouri River, approximately 19 miles north of Omaha, NE. The construction permit was issued by NRC on June 7, 1968, and the operating license was issued August 9, 1973. The unit consists of a Combustion Engineering (CE) pressurized-water reactor (PWR) nuclear steam supply system designed to generate 1500 MW-thermal, or approximately 475 MW-electric.

This SER presents the status of the staff's review of information submitted to the NRC through August 7, 2003. In its SER issued on April 21, 2003, the staff identified open and confirmatory items that had to be resolved before the staff could make a final determination on the application. These items and their resolutions are summarized in Sections 1.5 and 1.6 of this report. The staff's final conclusion of its review of the FCS LRA can be found in Section 6 of this SER.

ABBREVIATIONS

AB-FO	auxiliary boiler fuel oil
ac	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductor, steel reinforced
AERM	aging effect requiring management
AFW	auxiliary feedwater
AMP	aging management program
AMR	aging management review
ANSI	American National Standards Institute
AOV	air-operated valve
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AWWA	American Water Works Association
B&W	Babcock & Wilcox
B&WOG	Babcock & Wilcox Owners Group
BAC	boric acid corrosion
BL	Bulletin
BTP	branch technical position
BWR	boiling-water reactor
CA	compressed air
CAP	corrective action program
CASS	cast austenitic stainless steel
CCNPP	Calvert Cliffs Nuclear Power Plant
CCW	component cooling water
CE	Combustion Engineering; control element
CEA	control element assembly
CEDM	control element drive mechanism
CEOG	Combustion Engineering Owners Group
CFR	*Code of Federal Regulations*
CI	confirmatory item
CIAS	containment isolation actuation signal
CIV	containment isolation valve
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CQE	critical quality element
CR	condition report
CRD	control rod drive
CS	containment spray
CSB	core support barrel
CUF	cumulative usage factor
CVCS	chemical and volume control system
DBA	design-basis accident
DBD	design-basis document
DBE	design-basis event

ABBREVIATIONS (con't)

dc	direct current
DG	diesel generator
DGFO	emergency diesel generator fuel oil
DGLO	emergency diesel generator lube oil
DSS	diverse scram system
EA	engineering analysis
ECCS	emergency core cooling system
ECT	eddy current testing
EDG	emergency diesel generator
EEQ	electrical equipment qualification
EFPY	effective full-power year
EFWST	emergency feedwater storage tank
EOCI	Electric Overhead Crane Institute
EPRI	Electric Power Research Institute
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety features actuation system
FAC	flow-accelerated corrosion
FACTS	Fort Calhoun Automatic Cable Tracking System
FCS	Fort Calhoun Station, Unit 1
FHA	fire hazard analysis
FMP	fatigue monitoring program
FP	fire protection
FP-FO	fire protection fuel oil
FPP	fire protection program
FPS	feet per second
FSAR	final safety analysis report
FW	feedwater
GALL	Generic Aging Lessons Learned
GE	General Electric Co.
GEIS	generic environmental impact statement
GL	generic letter
GWD	gaseous waste disposal
HELB	high-energy line break
HEPA	high-efficiency particulate air
HPCI	high-pressure coolant injection
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
IA	instrument air
IASCC	irradiation-assisted stress-corrosion cracking
ICI	in-core instrumentation
IEEE	Institute of Electrical and Electronic Engineers
IGA	intergranular attack
IGSCC	intergranular stress-corrosion cracking
IN	information notice

ABBREVIATIONS (con't)

IPA	integrated plant assessment
ISG	interim staff guidance
ISI	inservice inspection
LBB	leak before break
LER	licensee event report
LOCA	loss-of-coolant accident
LPSI	low-pressure safety injection
LRA	license renewal application
LRDB	license renewal database
LTOP	low-temperature overpressure protection
LWD	liquid waste disposal
MCRE	main control room envelope
MFW	main feedwater
MIC	microbiologically influenced corrosion
Mo	molybdenum
Mn	manganese
MS	main steam
MSIV	main steam isolation valve
MW	megawatt
n/cm^2	neutrons per square centimeter
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NG	nitrogen gas
Ni	nickel
NPAR	nuclear plant aging research
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
OD	outside diameter
ODCM	offsite dose calculation manual
ODSCC	outer-diameter stress-corrosion cracking
OI	open item
OPPD	Omaha Public Power District
P&ID	piping and instrumentation diagram
PBD	program basis document
PM	preventive maintenance
POI	potential open item
PORV	power-operated relief valve
ppm	parts per million
PRA	probability and risk assessment; probabilistic risk assessment
PS	primary sampling
psia	pounds per square inch, atmospheric (pressure)
PS/PMP	periodic surveillance and preventive maintenance program

ABBREVIATIONS (con't)

P/T	pressure and temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
QA	quality assurance
RAI	request for additional information
RAMS	resource acquisition management system
RC	reactor coolant
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RIS	Regulatory Issue Summary
RMS	radiation monitoring system
RPS	reactor protection system
RS	reactor system
RT_{NDT}	reference temperature nil ductility
RT_{PTS}	PTS reference temperature
RTD	resistance temperature detector
RV	reactor vessel; relief valve
RVI	reactor vessel internals
RVII	reactor vessel internals inspection
RVIP	reactor vessel integrity program
RW	raw water
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SDC	shutdown cooling
SER	safety evaluation report
SFP	spent fuel pool
SFPC	spent fuel pool cooling
SG	steam generator
SGIS	steam generator isolation signal
SGP	steam generator program
SI	safety injection
SI&CS	safety injection and containment spray
SIAS	safety injection actuation signal
SIRWT	safety injection and refueling water tank
SMP	structures monitoring program
SO	standing order
SOC	Statements of Consideration
SOER	Significant Operating Experience Report
SPCS	steam and power conversion systems
SRP	Standard Review Plan

ABBREVIATIONS (con't)

SRP-LR	Standard Review Plan - license renewal
SSC	structures, systems, and components
SSEL	safe shutdown equipment list
SV	safety valve
T	thickness
TLAA	time-limited aging analysis
TR	topical report
UCS	Union of Concerned Scientists
UFHA	updated fire hazards analysis
UGS	upper guide structure
USAR	updated safety analysis report
USAS	United States of America Standards
USE	upper-shelf energy
UT	ultrasonic testing
VA	ventilating air
vac	volt alternating current
VCT	volume control tank
vdc	volt direct current
VHP	vessel head penetration

TABLE OF CONTENTS

SECTION 1

INTRODUCTION AND GENERAL INFORMATION

Section 1 - Table of Contents

1 Introduction and General Discussion

1.1 Introduction

This document is a safety evaluation report (SER) on the application for license renewal for the Fort Calhoun Station, Unit 1 (FCS), as filed by the Omaha Public Power District (OPPD or the applicant). By letters dated January 9 and April 5, 2002, OPPD submitted its application to the U.S. Nuclear Regulatory Commission (NRC or the Agency) for renewal of the FCS operating license for an additional 20 years. The NRC staff (the staff) prepared this report which summarizes the results of its safety review of the renewal application for compliance with the requirements of Title 10, Part 54 of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC license renewal project manager for the FCS license renewal review is William F. Burton. Mr. Burton may be contacted by calling 301-415-2853, or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001.

In its January 9, 2002, submittal letter, the applicant requested renewal of the operating license issued under Section 104b of the Atomic Energy Act of 1954, as amended, for FCS (license number DPR-40) for a period of 20 years beyond the current license expiration of midnight, August 9, 2013. The FCS site is located in Washington County, NE, on the west bank of the Missouri River, approximately 19 miles north of Omaha, NE. Construction began on Unit 1 in June 1968, and its operating license was issued on August 9, 1973. The unit consists of a Combustion Engineering (CE) pressurized-water reactor (PWR) nuclear steam supply system (NSSS) designed to generate 1500 MW-thermal, or approximately 475 MW-electric. Details concerning the plant and the site are found in the updated safety analysis report (USAR) for the unit.

The license renewal process proceeds along two tracks which consist of (1) a technical review of safety issues and (2) an environmental review. The requirements for these reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review for the FCS license renewal is based on the applicant's license renewal application (LRA) and on the answers to requests for additional information (RAIs) from the staff. In meetings and docketed correspondence, the applicant has also supplemented its answers to the RAIs. Unless otherwise noted, the staff reviewed and considered information submitted through August 7, 2003. The LRA and all pertinent information and materials, including the USAR mentioned above, are available to the public for review at the NRC Public Document Room, 11555 Rockville Pike, Room 1-F21, Rockville, MD, 20852-2738 (301-415-4737/800-397-4209); the W. Dale Clark Library, 215 South 15th Street, Omaha, NE 68102; and the Blair Public Library, 210 South 17th Street, Blair, NE 68008-2055. Material related to the LRA is also available through the NRC website at www.nrc.gov

This SER summarizes the results of the staff's safety review of the FCS LRA and delineates the scope of the technical details considered in evaluating the safety aspects of FCS' proposed operation for an additional 20 years beyond the term of the current operating license. The LRA was reviewed in accordance with the NRC regulations and the guidance provided in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants", dated July 2001 (SRP-LR).

Sections 2 through 4 of the SER address the staff's review and evaluation of license renewal issues that have been considered during the review of the application. Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). The conclusions of this report are in Section 6 of the SER.

Appendix A of this SER is a table that identifies the applicant's commitments associated with the renewal of the operating license. Appendix B contains a chronology of the principal correspondence between the NRC and the applicant related to the review of the application. Appendix C presents an index of the staff's RAIs and the applicant's responses. Appendix D is a list of principal contributors to the SER.

In accordance with 10 CFR Part 51, the staff prepared a draft for comment on the plant-specific supplement to the generic environmental impact statement (GEIS) that discusses the environmental considerations related to renewing the license for FCS. NUREG-1437, Supplement 12, the plant-specific draft supplement to the GEIS, was issued in January 2003. The final supplement to the GEIS was issued on August 15, 2003.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, operating licenses for commercial power reactors are issued for 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations-not on technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC held a workshop on nuclear power plant aging in anticipation of the interest in license renewal. That led the NRC to establish a comprehensive program plan for nuclear plant aging research (NPAR). On the basis of the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the NRC published the license renewal rule in 10 CFR Part 54 (the Rule). The NRC participated in an industry sponsored demonstration program to apply the rule to a pilot plant and to develop experience to establish implementation guidance. To establish a scope of review for license renewal, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing programs, particularly the implementation of the maintenance rule, which also manages plant aging phenomena. As a result, in 1995, the NRC amended the license renewal rule. The amended 10 CFR Part 54 established a regulatory process that is simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR Part 54 was amended to focus on managing the adverse effects of aging rather than on identifying age-related degradation unique to license renewal. The rule changes were intended to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions in the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the NRC pursued a separate rulemaking effort, 10 CFR Part 51, to focus the scope of the review of the environmental impacts of license renewal, in fulfillment of the NRC's responsibilities under the National Environmental Policy Act of 1969 (NEPA).

1.2.1 Safety Review

License renewal requirements for power reactors are based on two key principles.

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain plant SSCs in the period of extended operation, as well as a few other potential issues related to safety during the period of extended operation.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

In implementing these two principles, 10 CFR 54.4 defines the scope of license renewal as those SSCs (a) that are safety-related, (b) whose failure could affect safety-related functions, and (c) that are relied on to demonstrate compliance with the NRC's regulations for fire protection, environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transients without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), an applicant for a renewed license must review all SSCs within the scope of the Rule to identify SCs subject to an aging management review (AMR). SCs subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties, and that are not subject to replacement based on qualified life or specified time period. As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that the effects of aging will be managed in such a way that the intended function or functions of those SCs will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation. Active equipment, however, is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental aging effects that may occur for active equipment are more readily detectable and will be identified and corrected through routine surveillance, performance indicators, and maintenance. The surveillance and maintenance programs for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required throughout the period of extended operation. Section 54.21(d) requires that a supplement to the final safety analysis report (FSAR) contain a summary description of the programs and activities for managing the effects of aging.

Another requirement for license renewal is the identification and updating of time-limited aging analyses (TLAAs). During the design phase for a plant, certain assumptions are made about the length of time the plant will be operated; these assumptions are then incorporated into design calculations for several of the plant's SSCs. Under 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or must be projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging on these SSCs will be adequately managed for the period of extended operation.

In 2001, the NRC developed and issued Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This guide endorses an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline is NEI 95-10, Revision 3, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54-The License Renewal Rule," which was issued in March 2001. The NRC also prepared the SRP-LR which, along with the RG, was used to review this application.

The OPPD is the first license renewal applicant to fully utilize the process defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," dated July 2001. The purpose of GALL is to provide the staff with a summary of staff-approved aging management programs (AMPs) for the aging of most SCs that are subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry, and serves as a reference for both applicant and staff reviewers to quickly identify those AMPs and activities that the staff has determined will provide adequate aging management during the period of extended operation.

1.2.2 Environmental Review

The environmental protection regulation, 10 CFR Part 51, was revised in December 1996, to facilitate the environmental review for license renewal. The staff prepared a GEIS, in which it examined the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings into its environmental report. Analyses of those environmental impacts that must be evaluated on a plant-specific basis (Category 2 issues) must be included in the environmental report in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, including whether new and significant information existed that was not considered in the GEIS. As part of the NRC environmental scoping process, a public meeting was held on June 18, 2002, in Omaha, NE, to identify environmental issues specific to the plant. Results of the environmental review and a preliminary recommendation with respect to the license renewal action were documented in NRC's draft plant-specific supplement to the GEIS, which was issued by the NRC on January 6, 2003, and which was discussed at a separate public meeting held on February 26, 2003, in Omaha, NE. After consideration of the comments on the draft, NRC prepared NUREG-1437, Supplement 12, “Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants,” which was published on August 15, 2003.

1.3 Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the FCS LRA in accordance with Commission guidance and the requirements of 10 CFR Part 54. The standards for renewing a license are contained in 10 CFR 54.29. This SER describes the results of the staff’s safety review.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. The applicant provided this general information in Section 1 of its LRA for FCS, submitted by letter dated January 9, 2002.

In 10 CFR 54.19(b), the Commission requires that license renewal applications include “conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.” The applicant states the following in its LRA regarding this issue.

> The current indemnity agreement for Fort Calhoun Station, Unit 1 does not contain a specific expiration term for the operating license. Therefore, conforming changes to account for the expiration term of the proposed renewed license are not necessary, unless the license number is changed upon issuance of the renewed license.

The staff intends to maintain the license type and number upon issuance of the renewed license. Therefore, there is no need to make conforming changes to the indemnity agreement, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility must contain (a) an IPA, (b) a description of CLB changes during staff review of the application, (c) an evaluation of TLAAs, and (d) an FSAR Supplement. Sections 3 and 4, as well as Sections A and B, of the LRA address the license renewal requirements of 10 CFR 54.21(a), (c), and (d), respectively.

In 10 CFR 54.21(b), the Commission requires that each year following submittal of the application, and at least 3 months before the scheduled completion of the staff’s review, an amendment to the renewal application must be submitted that identifies any change to the CLB of the facility that materially affects the contents of the license renewal application, including the FSAR Supplement. This information was provided by letter dated May 16, 2003. Therefore the requirements of 10 CFR 54.21(b) have been met.

In 10 CFR 54.22, the Commission lists requirements regarding technical specifications. In Appendix D of the LRA, the applicant stated that no changes to the FCS Technical Specifications are necessary. This adequately addresses the requirements of 10 CFR 54.22.

The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with the NRC’s regulations and the guidance provided by the SRP-LR. The staff’s evaluation of the LRA in accordance with 10 CFR 54.21 and 10 CFR 54.22 is contained in Sections 2, 3, and 4 of this report.

The staff's evaluation of the environmental information required by 10 CFR 54.23 is included in the draft and final plant-specific supplements to the GEIS that will state the considerations related to renewing the license for FCS. When the report of the ACRS, required by 10 CFR 54.25, is issued, it will be incorporated into Section 5 of this SER. The findings required by 10 CFR 54.29 are included as Section 6 of this report.

1.4 Interim Staff Guidance

The license renewal program is a living program. The NRC staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the NRC's performance goals of maintaining safety, improving effectiveness and efficiency, reducing unnecessary regulatory burden, and increasing public confidence. The lessons learned are captured in interim staff guidance (ISG) for use by the staff and interested stakeholders until the improved license renewal guidance documents are revised.

The current set of relevant ISGs that have been issued by the staff, and the SER sections in which the issues are addressed by the staff, is provided below.

Interim Staff Guidance for License Renewal

ISG Issue (**Approved ISG No.)**	**Purpose**	**SER Section**
Station Blackout (SBO) Scoping **(ISG-02)**	The license renewal rule 10 CFR 54.4(a)(3) includes 10 CFR 50.63(a)(1)-SBO. The SBO rule requires that a plant must withstand and recover from an SBO event. The recovery time for offsite power is much faster than that of EDGs. The offsite power system should be included within the scope of license renewal.	2.5.2 3.6.2.4.4
Concrete Aging Management Program **(ISG-03)**	Lessons learned from the GALL Demonstration project indicated that GALL is not clear whether concrete needs any AMPs.	3.5.2.2.1 3.5.2.2.2 3.5.2.4.1 3.5.2.4.2

Fire Protection (FP) System Piping **(ISG-04)**	To clarify staff position for wall thinning of FP piping system in GALL AMPs (XI.M26 and XI.M27). New guidance is that there is no need to disassemble FP piping, as oxygen can be introduced in the FP piping which can accelerate corrosion. Instead, use nonintrusive method such as volumetric inspection. Testing of sprinkler heads should be performed at year 50 of the sprinkler systems service life, not at year 50 of plant operations, with subsequent sprinkler head tests every 10 years thereafter. Eliminated Halon/carbon dioxide system inspections for charging pressure, valve line ups, and automatic mode of operation test from GALL, as the staff considers these test verifications to be operational activities.	3.0.3.9

Identification and Treatment of Electrical Fuse Holder **(ISG-05)**	To include fuse holder AMR and AMP (i.e., same as terminal blocks and other electrical connections). The position includes only fuse holders that are not inside the enclosure of active components (e.g., inside of switchgears and inverters). Operating experience finds that metallic clamps (spring-loaded clips) have a history of age-related failures from aging stressors such as vibration, thermal cycling, mechanical stress, corrosion, and chemical contamination. The staff finds that visual inspection of fuse clips is not sufficient to detect the aging effects from fatigue, mechanical stress, and vibration.	3.6.2.4.5

1.5 Summary of Open Items

As a result of its review of the LRA for FCS, including additional information submitted to the NRC through August 7, 2003, the staff identified the following open items. An issue was open if the applicant had not presented a sufficient basis for resolution, or if information provided to the staff in recent applicant submittals in response to potential open items (POIs) had yet to be reviewed by the staff. Each open item was assigned a unique identifying number.

Item	Description
2.2-1	During the AMR inspection and audit, the team reviewed the onsite engineering analysis (EA)-FC-00-149, "NSR Steam and Water Systems Impacting SSC Within Scope For License Renewal." In this EA, the applicant identified piping systems and associated reference drawings for those systems that have met the 10 CFR 54.4(a)(2) criteria for spatial interaction. However, after discussions with the staff, the applicant indicated that some of these systems are already identified as being within the scope of license renewal but were not identified as being within scope in the LRA. The applicant also stated that the Flow-Accelerated Corrosion (FAC), Chemistry, General Corrosion of External Surfaces, and Structures Monitoring Programs are the applicable AMPs to manage aging effects for components in these systems.

On the basis of its review, the staff determined that the information, as provided by the applicant, was not sufficient for the staff's scoping and AMRs for these 10 CFR 54.4(a)(2) SSCs. For the additional SSCs that had been brought into scope to meet the 10 CFR 54.4(a)(2) criterion, the applicant was requested to provide scoping information to the component level equivalent to that of the original LRA. This information was necessary for the staff to be able to determine that all the components required by 10 CFR 54.4(a)(2) to be within the scope of license renewal and subject to an AMR had been correctly identified. Also, the applicant was requested to provide revised and/or new Section 2 tables, including links to Section 3 tables, so that the staff could perform an AMR to determine whether the applicant had identified the proper aging effects for the combination of the materials and environments, and had provided an adequate AMP for managing the corresponding aging effects for these SSCs.

By letter dated February 20, 2003, the staff issued POI-1(a) requesting that the applicant provide the above information. By letter dated March 14, 2003, the applicant provided the requested information. The staff reviewed the information and found that the applicant had adequately identified the SSCs within the scope of license renewal as a result of meeting the 10 CFR 54.4(a)(2) scoping criterion. POI-1(a) is resolved. However, the staff still had to review the AMR results for the additional components brought into scope and subject to an AMR to determine whether they would be adequately managed during the period of extended operation. This was identified as Open Item 2.2-1.

The staff has completed its review of the aging management information provided by the applicant and has determined that the SCs discussed above will be adequately managed during the period of extended operation. On this basis, Open Item 2.2-1 is closed.

2.2-2 Engineering Analysis (EA) FC-00-127, "Miscellaneous Systems, Penetrations, and Components," stated that the compressed air, demineralized water, and steam generator feedwater blowdown systems contain components that were functionally realigned. The team noted that this was inconsistent with LRA Table 2.2-1 and LRA Section 2.3.2.2. LRA Table 2.2-1 stated that containment isolation and/or pressure boundary components in the compressed air, demineralized water, and blowpipe systems were functionally realigned to the commodity group, "Containment Penetration and System Interface Components for Non-CQE Related System." However, LRA Section 2.3.2.2, which described this commodity group, stated that the group contains containment isolation valves (CIVs) from the feedwater blowdown, compressed air, blowpipe, and demineralized water systems, as well as the piping between the containment penetrations and the CIVs. It also stated that the demineralized water heat exchangers are included in the commodity group in order to maintain the component cooling water (CCW) system pressure boundary. LRA Table 2.2-1 and the description in LRA Section 2.3.2.2 are inconsistent in that the blowdown system was not identified in LRA Table 2.2-1 as having components that were functionally realigned. By letter dated February 20, 2003, the staff issued

POI-1(d) requesting the applicant to resolve this discrepancy between LRA Table 2.2-1 and the description in LRA Section 2.3.2.2, and to provide revised Section 2 tables and, if necessary, revised Section 3 tables to accurately describe which systems and/or components have been functionally realigned and how the components will be managed.

By letter dated March 14, 2003, the applicant responded to POI-1(d), providing revisions to LRA Table 2.2-1 and LRA Section 2.3.2.2 and an additional drawing to clearly identify the blowpipe system. On the basis of the applicant's response, POI-1(d) was resolved. However, the staff still needed to review the information provided to ensure that all components within scope and subject to an AMR had been identified. This was identified as Open Item 2.2-2.

The staff has now completed its review and confirmed that no components within these systems were omitted from scope and none that are subject to an AMR were omitted. On the basis of the staff's review, as described above, Open Item 2.2-2 is closed.

2.3.3.15-1 Section 2.3.3.15 of the LRA stated that the raw water (RW) discharge from the CCW system heat exchangers and the discharge from the direct cooling RW header flow into the circulating water discharge tunnel. Table 2.2-1 of the LRA designated the circulating water system as outside of license renewal scope without specific justification, but failure of the pressure boundary of buried piping or tunnels creates the potential for a loss of RW flow. Therefore, the location of the license renewal boundary at the discharge pipes for the RW system, rather than at the outlet from the circulating water discharge tunnel, had not been adequately justified. By letter dated February 20, 2003, the staff issued POI-3(a) requesting the applicant to justify the location of the license renewal boundary.

By letter dated March 14, 2003, the applicant responded to this POI stating that the location for the RW discharge license renewal boundary at check valves CW-188 and CW-189, upstream of the circulating water discharge tunnel, had been revised. The applicant included the circulating water discharge tunnel within the scope of license renewal as part of the intake structure. The applicant referenced a separate letter dated March 14, 2003, which included revised boundary drawing 11405-M-100 and new boundary drawing 11405-M-257, Sh. 2, as attachments. These drawings showed that a continuous flow path from the RW system to the river outfall had been included within scope for license renewal. This resolves the scoping issues associated with POI-3(a), but the expansion of scope introduced the need for evaluation of the applicant's AMR for the discharge tunnel.

In its POI response, the applicant provided the following discussion regarding the AMR of the discharge tunnel.

1. The circulating water discharge tunnel is constructed of reinforced concrete with a nominal wall thickness of 2' or greater and nominal floor/ceiling thicknesses of 2'-6" or greater throughout. The concrete circulating water discharge tunnel walls, floor and ceiling are constructed of Type B concrete in accordance with ACI 201.2R as specified in NUREG-1557.

2. The concrete is not exposed to aggressive river water or groundwater. The concrete that surrounds the embedded steel has a pH greater than or equal to 12.5. The concrete mix design specified a water-to-cement ratio of 0.44 and air entrainment of 5.00% + 1.00% for Class B concrete. The concrete at FCS was designed in accordance with ACI 318-63 (per USAR Section 5.3.1 Revision 0 and USAR Section 5.11.3.1 Revision 2).

3. The maximum flow rate in the circulating water tunnel is well below the velocity of 25 fps required to initiate abrasion. The calculated highest water velocity for a closed conduit is in the warm water recirculating tunnel at 12.6 fps. Therefore, this aging effect is not credible.

4. Per NUREG-1557, corrosion of embedded steel is not significant for concrete structures above or below grade that are exposed to a non-aggressive environment. A non-aggressive environment, as defined by NUREG-1557, is one with a pH greater than 11.5 or chlorides less than 500 ppm. NUREG-1557 also concludes that corrosion of embedded steel is not significant for concrete structures exposed to an aggressive environment but have a low water-to-cement ratio, adequate air entrainment, and designed in accordance with ACI 318-63 or ACI 349-85. A low water-to-cement ratio is defined as 0.35 to 0.45 and adequate air entrainment is defined as 3 to 6 percent. Therefore, corrosion of embedded steel is not credible.

5. The freeze/thaw exposure category is “Severe” since the concrete of concern is in direct contact with the soil. Based on recent analyses, the groundwater and river water contain minimal amounts of chlorides (8.0 ppm and 14.0 ppm respectively), sulfates (79 ppm and 229 ppm respectively), and the pH is slightly alkaline (7.48 and 8.39 respectively); therefore, the exposure category for sulfates, chlorides, and acids is “Mild”, and concrete degradation is not credible for the circulating water discharge tunnel.

6. The total flow of the raw water equates to less than 5% of the total volume of the circulating water discharge tunnel.

Based on the installation conditions enumerated above, the conditions specified in NUREG-1557 have been satisfied; therefore, minimal or no aging effects will be realized in the circulating water discharge tunnel. Tunnel failure will not result in a loss of the raw water intended function during the period of extended operation. To verify this assumption, the applicant committed to performing a one-time inspection of the circulating water discharge tunnel as part of the one-time inspection program (B.3.5).

The staff evaluated the information provided in response to POI-3(a) and found that the applicant had brought the circulating water discharge tunnel within scope. Therefore, POI-3(a) was resolved. However, the staff still had to review the aging management results associated with the expanded scope. This was identified as Open Item 2.3.3.15-1.

By letter dated July 7, 2003, the applicant revised the response contained in its submittal dated March 14, 2003. The applicant has chosen to manage aging of the circulating water tunnel as part of the structures monitoring program instead of the one-time inspection program. The staff has reviewed the structures monitoring program to ensure that the scope of the program includes the circulating water tunnel. LRA Section B.2.10 describes the structures monitoring program. The program description states that it is consistent with GALL Program XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants.” The scope of GALL program XI.S7 includes intake and discharge structures. Because the circulating water tunnel is a discharge structure, it falls within the scope of XI.S7.

As stated above, the additional structural components of the circulating water discharge tunnel that were brought into scope were included and evaluated as part of the intake structure. The staff confirmed that the circulating water structural components brought into scope were already identified in LRA Table 2.4.2.3-1 for the intake structure. Therefore, the aging management results for the intake structure are applicable to the circulating water discharge tunnel. As discussed in Section 3.5.2.4.2 of this SER, the staff has concluded that the applicant has demonstrated that the aging effects associated with the components in structures outside containment (including the intake structure) will be adequately managed so that their intended functions will continue to be performed in accordance with the CLB for the period of extended operation. On this basis, the staff concludes that the components associated with the circulating water discharge tunnel, as part of the intake structure, will also be adequately managed such that the components will continue to perform their intended functions for the period of extended operation. Open Item 2.3.3.15-1 is closed.

3.0-1 In its letter dated March 14, 2003, the applicant provided revisions to many tables in LRA Sections 2 and 3. In Appendix A of the referenced letter, OPPD resubmitted LRA tables incorporating changes made since the April 2002 LRA revision. The revised tables were formatted to indicate which changes were made as a result of responses to NRC RAIs/POIs or as a result of additional applicant reviews of system EAs.

Subsequent to the submittal, the NRC project manager created a summary matrix of the LRA table changes. On May 28 and 29, 2003, the NRC conducted a public meeting to discuss the FCS SER open and confirmatory items. During the course of that meeting, the LRA table changes, and the bases for the changes, were discussed with the applicable NRC reviewers. The applicant revised the summary matrix to reflect the meeting conclusions. Appendix A of the applicant’s July 7, 2003, submittal, and clarifications provided by the applicant on August 7, 2003, contain the revised summary of revisions to the FCS LRA tables matrix. The matrix columns include the line item number, the table in which the change was made, a description of the change, the reason for the change, whether the change was accepted at the public meeting, and clarification about the change where requested by the NRC reviewers.

The staff reviewed the revised information to determine whether the revisions alter the staff’s conclusions as documented in the open items of the SER. As a result of its review of the revised information, the staff concludes that the revisions provided by the applicant demonstrate that the SCs at FCS that are subject to an AMR will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). Open Item 3.0-1 is closed.

3.3.2.4.1.2-1 For the regenerative heat exchanger, which is constructed of stainless steel and exposed to chemically treated borated water, LRA Table 2.3.3.1-1 cited link 3.3.1.08 for aging management of cracking due to stress-corrosion cracking

(SCC), consistent with the GALL Report. This link stated that the aging management will consist of the chemistry program, with the effectiveness of the chemistry program verified by inspections performed using either the one-time inspection program, cooling water corrosion program, or periodic surveillance and preventive maintenance program. In discussions during the AMR inspection and audit, the applicant stated that the regenerative heat exchanger is welded such that the internals are not accessible. Due to its construction, the applicant stated that the aging management of the regenerative heat exchanger would consist of the chemistry program with further evaluation of cracking due to SCC provided by inspection of the welds via the inservice inspection (ISI) program. The applicant considered this adequate aging management to support the pressure boundary intended function of the heat exchanger shell. Though the staff agrees that this is acceptable for the external pressure boundary, the staff notes that it would not detect degradation of the regenerative heat exchanger tubes which could allow inventory to flow from the charging to the letdown side of the chemical and volume control system (CVCS). This would reduce the effectiveness of the CVCS for managing reactor coolant system (RCS) chemistry, and may also reduce the ability of the system to inject borated water during an event. Therefore, the proposed aging management may not be adequate to ensure that this intended function of the heat exchanger is maintained.

By letter dated February 20, 2003, the staff issued POI-10(b) and POI-10(i) requesting the applicant to describe inspections of the regenerative heat exchanger internals that would verify the absence of the identified aging effects, or to justify that degradation of the internals would not result in loss of function. By letter dated March 14, 2003, the applicant responded to POI-10(b) and POI-10(i), stating that a potential failure of the internal boundary between the two sides of the regenerative heat exchanger would not affect the inventory available for injection during an accident. The only function of the boundary is to provide for heat transfer during normal letdown operation. This function is not required during an accident. On the basis of its review of the information in the POI responses, the staff found that the applicant's response did not explain how the plant can withstand the regulated events if the pressure boundary fails.

This pressure boundary function is important for at least two reasons over and above the normal CVCS function of maintaining RCS water chemistry. The first reason involves getting adequate boron injection during an event. The second reason involves isolating a letdown line break, which is a containment bypass loss-of-coolant accident (LOCA) (note that the CVCS injection path is the normally used path for the controlled cooldown during Appendix R events).

With regard to injection during an event, letdown is designed to isolate during any event in which there is a need for injection. If the letdown heat exchanger tubes leak sufficiently, there could be a continued loss of inventory via the letdown flowpath because one of the two letdown isolation valves is upstream of the heat exchanger, and would be bypassed. This would leave a single valve to isolate letdown and support injection.

Letdown is also designed to isolate during any breaks in the system to stop containment bypass. Again, if the letdown heat exchanger tubes leak sufficiently, the inboard isolation valve would be bypassed and a single train/single valve would be relied on to stop the containment bypass LOCA.

On the basis of this information, the staff requested that the applicant provide additional information to demonstrate how degradation of the heat exchanger internals will not adversely impact the injection function, or to provide information on how the internals will be managed during the period of extended operation to ensure that the injection function is maintained. This was identified as Open Item 3.3.2.4.1.2-1.

By letter dated July 7, 2003, the applicant stated, in part, the following.

> ...flow through a tube leak in the regenerative heat exchanger (RHX) is not possible during design basis events (DBEs) because the letdown (tube) side of the RHX would be isolated in response to the events. This isolation would occur automatically upstream at the inboard containment isolation valve from the hot leg (TCV-202), and downstream at the outboard containment isolation valve (HCV-204). Backflow from the RCS through the RHX shell side is not possible due to the charging header check valves to the loops (CH-283 and -284) and the spray line (CH-285). Additionally, the containment isolation valves, as well as the letdown control valves (LCV-101-1 and -2), fail closed upon loss of air, loss of power, or loss of signal. The charging pumps, the RHX, and letdown are not credited in the USAR Chapter 14 safety analyses for plant shutdown nor are they used during a DBE (see Section 9.2.5 of the USAR).

The staff reviewed the information in the FCS USAR and the applicant's letter dated July 7, 2003, related to flow through the RHX tubes during design basis events or the regulated events covered by 10 CFR Part 54. The staff also considered whether the RHX tubes should be considered a design feature that was inherently credited to mitigate a release in the event of a CVCS line break (e.g., the charging line or the letdown line outside containment). The staff concludes that, due to the design of the FCS CVCS and the operation of the CVCS isolation valves, there is no credible scenario that would result in flow through the RHX tubes during design basis events or the regulated events covered by 10 CFR Part 54, and that pressure integrity of the RHX tubes is not required to isolate flow during a CVCS line break. Therefore, the staff concludes that degradation of the RHX tubes will not result in the loss of component and CVCS intended functions. Open Item 3.3.2.4.1.2-1 is closed.

3.6.2.3.1.2-1 The staff reviewed the USAR Supplement for the non-EQ cable AMP and found that the supplement did not provide an adequate description of the revised program, as required by 10 CFR 54.21(d). The applicant was requested to submit to the staff a revised USAR Supplement that is consistent with the descriptions for GALL AMPs XI.E1, XI.E2, and XI.E3 to satisfy 10 CFR 54.21(d). This was identified as Open Item 3.6.2.3.1.2-1.

By letter dated July 7, 2003, the applicant submitted the following revised USAR Supplement Section A.2.15 description that supersedes the Section A.2.15 in the LRA.

A.2.15 Non-EQ Cable Aging Management Program

The FCS Non-EQ Cable Aging Management Program is a new program that provides aging management of (1) non-environmentally qualified electrical cables and connections exposed to an adverse localized environment caused by heat, radiation, or moisture; (2) non-environmentally qualified electrical cables used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance, and are exposed to an adverse localized environment caused by heat, radiation, or moisture; and (3) non-environmentally qualified inaccessible medium-voltage cables exposed to an adverse localized environment caused by moisture and voltage exposure.

Aging management is provided by the following actions:

1. Accessible electrical cables and connections installed in adverse localized environments will be inspected prior to the period of extended operation and at least once every 10 years for cable and connector jacket surface anomalies, such as embrittlement, discoloration, cracking, swelling, or surface contamination.

2. Electrical cables used in circuits with sensitive, low-level signals, such as radiation monitoring and nuclear instrumentation, are tested as part of the instrumentation loop calibration at the normal calibration frequency.

3. In-scope medium voltage cables exposed to significant moisture and significant voltage will be tested prior to the period of extended operation and at least once every 10 years to provide an indication of the condition of the conductor insulation. The test will be a state-of-the-art test at the time the test is performed.

This program considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, EPRI TR-109619, and EPRI TR-103834-P1-2.

The staff reviewed the above information and finds that the revised USAR Supplement provides an adequate summary description of the revised Non-EQ Aging Management Program and that the program is consistent with GALL Programs XI.E1, XI.E2, and XI.E3. Open Item 3.6.2.3.1.2-1 is closed.

3.6.2.4.3.2-1 LRA Table 2.5.20-1 stated that electrical bus bars and bus bar standoffs have no aging effects that require management. The basis for the applicant's conclusion was unclear to the staff. By letter dated February 20, 2003, the staff issued POI-6(b) requesting the applicant to provide information on the components' materials and environments, along with the basis for concluding that these components have no plausible aging effects. By letter dated March 14, 2003, the applicant responded to POI-6(b), stating the following.

The bus bar materials are copper and aluminum; their environment is in indoor air and outdoor air. In accordance with EPRI TR-114882, Non-Class1 Mechanical Implementation Guideline and Mechanical Tools, Revision 2, 1999, no aging effects were identified for aluminum, aluminum alloys, copper, or copper alloys (brass, bronze) in an indoor or outdoor air environment.

The stand offs include fiberglass reinforced polyester resin and porcelain materials that are in ambient air external environment and are not continuously wetted. Internal environments are not applicable.

Table 7-17 of EPRI NP-1558, A Review of Equipment Aging Theory and Technology lists the continuous use temperature of plastics. The continuous use temperature [a] listed for polyester with 40% glass content is 266 °F[b] (compared with the bounding temperature value of 122 °F). Applying the Arrhenius methodology, it is clear that fiberglass reinforced polyester is acceptable. Figure C-2 of EPRI NP-1558 contains the relative radiation stability of thermosetting resins. The threshold for gamma radiation for polyester (glass filled) is 1,000,000,000 Rads (compared with the bounding 60-year radiation dose of less than 1,000 Rads).

a. Continuous use temperatures were determined as the temperatures corresponding to 100,000 hours (11.4 years) on the Arrhenius curve of the material for an endpoint of 50% reduction in tensile strength.

b. Based on retention of tensile strength taken at 500 degrees F.

On the basis of its review of the applicant's response to POI-6(b), the staff was concerned that the applicant may not have considered all the aging effects of the bus bars/ducts. The staff discussed this issue with the applicant, pointing out that the industry experience has indicated several problems with the bus bars/ducts, such as loosening of splice plate bolts, degradation of Noryl insulation, presence of moisture or debris, oxidation of aluminum electrical connections, and corrosion of metallic components. The staff requested that the applicant provide a description of the AMP used to detect the above aging effects, or provide justification why such a program is not needed. This was identified as Open Item 3.6.2.4.3.2-1.

By letter dated July 7, 2003, the applicant responded to Open Item 3.6.2.4.3.2-1, stating that when scoping and screening were performed for bus bars at FCS, as a conservative measure, all bus bars were included within the scope of license renewal, with the exception of those associated with SBO. SBO beyond the plant boundary was added later in response to a staff RAI and the NRC ISG on SBO. All of the in-plant bus bars are inside the enclosure of an active component, such as switchgear, power supplies, etc., and are considered to be piece parts of the larger assembly. Per 10 CFR 54.21, OPPD considers them outside the scope for license renewal.

The applicant stated that the SBO restoration buses (nonsegregated and iso-phase) are fed from the 161 Kv and 345 Kv transmission lines from the switchyard primary side of the transformers (auxiliary and main) and connect to the plant from the secondary side of the transformers by bus work (non-segregated from the auxiliary transformers and isophase from the main). The isophase bus, which is an aluminum tube contained in a tube-like aluminum enclosure, connects the main transformer to the main generator and to the unit auxiliary transformers. The isophase bus is continuously air-cooled and no moisture accumulation has ever been observed. The isophase bus connects from the main to the auxiliary transformers with bolted connections. The connections of the buses to the transformers are inspected and greased periodically in accordance with OPPD Substation Maintenance Department procedures. The inspections are performed on a "train outage schedule" (i.e., in one refueling outage, one bus is inspected and during the next outage, the other bus is inspected).

The auxiliary transformers utilize nonsegregated copper buses to connect to the 4160-volt distribution system. Use of flexible copper buses minimizes the effects of vibration from end devices. The connections of the buses to the transformers are inspected and greased periodically in accordance with OPPD Substation Maintenance Department procedures. The nonsegregated bus work is insulated. However, past inspections of this area revealed peeling or flaking of the insulation (inspections were performed during the early- to mid- 1970s, prior to implementation of the current Corrective Action Program). To preclude further degradation, OPPD taped a good portion of the non-segregated buses, including the affected areas. The taping was done with Bishops High Voltage tape, with the ends taped off with Scotch 88 tape. OPPD inspects these buses on a "train outage schedule." These buses are inspected using a plant maintenance procedure which inspects the bus and the switchgear cubicles associated with that bus.

The bus bars credited in the SBO restoration path are all connected to the auxiliary transformers by bolted connections. The aging of the bolted connections is managed through implementation of the OPPD Periodic Surveillance and Preventive Maintenance Program. The OPPD substation maintenance crew periodically inspects all bolted connections. The torque values of the bolted connections are also periodically checked. Routine inspection and cleaning of the buses by Substation Maintenance Department and FCS Maintenance Department crews preclude the buildup of any dirt or debris or the existence of loose bolting.

The description of the Periodic Surveillance and Preventive Maintenance Program in LRA Section A.2.18 (the USAR Supplement) is not at the level of detail that warrants mention of bus bar aging management, therefore, this section has not been revised. However, OPPD has revised the Periodic Surveillance and Preventive Maintenance Program description in LRA Section B.2.7 to include Substation–SBO Restoration in the program scope. The program's activities also check bus connectors for loss of torque and degradation of insulation wrap. The revised LRA Section B.2.7 is provided below.

B.2.7 Periodic Surveillance And Preventive Maintenance (PM) Program

The stated purpose of the PM program is to prevent or minimize equipment breakdown and to maintain equipment in a condition that will enable it to perform its normal and emergency functions. The program and the site administrative control processes provide for a systematic approach in establishing the method, frequency, acceptance criteria, and documentation of results.

The FCS Periodic Surveillance and Preventive Maintenance Program consists of periodic inspections and tests that are relied on to manage aging for system and structural components and that are not evaluated as part of the other aging management programs addressed in this appendix. The preventive maintenance and surveillance testing activities are implemented through periodic work orders that provide for assurance of functionality of the components by confirmation of integrity of applicable parameters.

EVALUATION AND TECHNICAL BASIS

(1) Scope of Program:

The FCS Periodic Surveillance and Preventive Maintenance Program provides for periodic inspection and testing of components in the following systems and structures.

- Auxiliary Building
- Auxiliary Building HVAC
- Auxiliary Feedwater
- Chemical and Volume Control
- Component Cooling
- Containment
- Containment HVAC
- Control Room HVAC and Toxic Gas Monitoring
- Diesel Generator Lube Oil
- Duct Banks
- Emergency Diesel Generators
- Fire Protection
- Fuel Handling Equipment/Heavy Load Cranes
- Intake Structure
- Liquid Waste Disposal
- Containment Penetration, and System Interface Components for Non-CQE Systems
- Reactor Coolant
- Safety Injection and Containment Spray
- Ventilating Air
- Substation – SBO Restoration

(2) Preventive Actions:

The Periodic Surveillance and Preventive Maintenance Program includes periodic refurbishment or replacement of components, which could be considered to be preventive or mitigative actions. The inspections and testing to identify component aging degradation effects do not constitute preventive actions in the context of this element.

(3) Parameters Monitored or Inspected:

Inspection and testing activities monitor parameters including surface condition, loss of material, presence of corrosion products, signs of cracking and presence of water in oil samples.

(4) Detection of Aging Effects:

Preventive maintenance and surveillance testing activities provide for periodic component inspections and testing to detect the following aging effects and mechanisms:

- Change in Material Properties
- Cracking
- Fouling
- Loss of Material
- Loss of Material – Crevice Corrosion
- Loss of Material – Fretting
- Degradation of insulation wrap
- Loss of Material – General Corrosion
- Loss of Material - Pitting Corrosion
- Loss of Material - Pitting/Crevice/Gen. Corrosion
- Loss of Material – Wear
- Separation
- Loss of Torque

The extent and schedule of the inspections and testing assures detection of component degradation prior to the loss of their intended functions. Established techniques such as visual inspections and dye penetrant testing are used.

(5) Monitoring and Trending:

Preventive maintenance and surveillance testing activities provide for monitoring and trending of aging degradation. Inspection intervals are established such that they provide for timely detection of component degradation. Inspection intervals are dependent on the component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations.

The program includes provisions for monitoring and trending with the stated intent of identifying potential failures or degradation and making adjustments to ensure components remain capable of performing their functions. PM review and update guidelines are provided that include adjustment of PM task and frequency based on the as-found results of previous performance of the PM. In particular, responsible system engineers are required to periodically review the results of preventive maintenance and recommend changes based on these reviews. The program includes guidance to assist the system engineers in achieving efficient and effective trending.

(6) Acceptance Criteria:

Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in the specific inspection and testing procedures. They confirm component integrity by verifying the absence of the aging effect or by comparing applicable parameters to limits based on the applicable intended function(s) as established by the plant design basis.

(7) Corrective Actions:

Identified deviations are evaluated within the FCS corrective action process, which includes provisions for root cause determinations and corrective actions to prevent recurrence as dictated by the significance of the deviation. The FCS corrective action process is in accordance with 10 CFR 50 Appendix B.

(8) Confirmation Process:

The FCS corrective action process is in accordance with 10 CFR 50 Appendix B and includes:

- Reviews to assure that proposed actions are adequate;
- Tracking and reporting of open corrective actions; and
- For root cause determinations, reviews of corrective action effectiveness.

(9) Administrative Controls:

All credited aging management activities are subject to the FCS administrative controls process, which is in accordance with 10 CFR 50 Appendix B and requires formal reviews and approvals.

(10) Operating Experience:

Periodic surveillance and preventive maintenance activities have been in place at FCS since the plant began operation. These activities have a demonstrated history of detecting damaged and degraded components and causing their repair or replacement in accordance with the site corrective action process. With few exceptions, age-related degradation adverse to component intended functions was discovered and corrective actions were taken prior to loss of intended function.

Conclusion:

The Periodic Surveillance and Preventive Maintenance Program assures that various aging effects are managed for a wide range of components at FCS. Based on the program structure and administrative processes and FCS operating experience, there is reasonable assurance that the credited inspection and testing activities of the Periodic Surveillance and Preventive Maintenance Program will continue to adequately manage the identified aging effects of the applicable components so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation.

The staff reviewed the applicant's response to Open Item 3.6.2.4.3.2-1, including the revised aging management program description, and finds that the applicant has provided an acceptable aging management program to manage the aging effects associated with the bus bars/ducts. On this basis, Open Item 3.6.2.4.3.2-1 is closed.

3.6.2.4.4.2-1 The aging effect for the transmission aluminum conductor-steel reinforced (ACRS) conductor is loss of conductor strength and vibration. The applicant addressed the vibration and the aluminum portion of the conductor, but did not address the steel portion. The most prevalent mechanism contributing to loss of conductor strength is corrosion, which includes corrosion of steel core and aluminum strand pitting. The staff requested that the applicant provide a description of its AMPs used to manage the aging effects in high-voltage conductors, or provide justification for why such programs are not needed. This was identified as Open Item 3.6.2.4.4.2-1.

By letter dated July 7, 2003, the applicant explained that it had performed a thorough review of industry operating experience related to the aging effects on high-voltage components, including ACSR. A detailed discussion on surface contaminants was provided in response to POI-6a (LIC-03-0035, dated March 14, 2003). The portion of that discussion on surface contaminants also applies to ACSR steel core.

The aging effects identified for high-voltage insulators, transmission conductors, switchyard bus, and un-insulated ground conductors are not heat-related, so ohmic heating is not required to be addressed (the applicant referenced the License Renewal Electrical Handbook, Electronic Power Research Institute (EPRI) 1003057, Final Report, December 2001, page 12-2, Ohmic Heating for Power Applications).

For ACSR conductors, corrosion degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality, which includes suspended particles, chemistry, SO_2 concentration in air, precipitation, fog chemistry, and meteorological conditions (the applicant referenced the EPRI License Renewal Electrical Handbook, pages 581 and 584). Corrosion of ACSR conductors is a very slow-acting aging effect that is even slower in rural areas which generally have less suspended particles and SO_2 concentrations in the air than urban areas. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion.

There is a set percentage of composite conductor strength established at which a transmission conductor is replaced. As illustrated in EPRI License Renewal Electrical Handbook, Final Report 1003057, December 2001, page 13-6, there is an ample strength margin to maintain the transmission conductor intended function through the period of extended operation.

On the basis of the above, the applicant determined that corrosion on high-voltage conductors is not a significant aging mechanism at FCS, and loss of conductor strength is, therefore, not an aging effect requiring management. There are no applicable aging effects that could cause the loss of the intended function of the transmission conductors for the period of extended operation.

The staff reviewed the applicant's response to Open Item 3.6.2.4.4.2-1 and agrees that the information provided in the EPRI electrical handbook confirms that there is adequate margin to maintain the conductor function through the period of extended operation, and finds that the applicant has provided an acceptable justification for not providing aging management for the ACSR conductor. The staff Open Item 3.6.2.4.4.2-1 is closed.

3.6.2.4.5.2-1 In LRA Section 2.5.1, “Cables and Connectors,” the applicant identified fuse blocks as components within the scope of license renewal and subject to an AMR. The staff was unsure whether fuse holders were included within the component type, “Fuse Block.” By letter dated February 20, 2003, the staff issued POI-1(c) requesting the applicant to clarify whether fuse holders are within the scope of license renewal and subject to an AMR, and, if fuse holders are brought into scope and require aging management, to provide the associated aging management information.

By letter dated March 14, 2003, the applicant provided the following requested information.

> Fuse holders are in the scope of license renewal as part of the cable and connector scoping and screening analysis. There are no fuse holders attached to electrical penetrations at FCS. Fuse holders at FCS that are within active enclosures such as power supplies, switchgear, and Motor Control Centers are considered outside the scope for license renewal. There are no fuse holders at FCS exposed to vibration or environments that would cause corrosion, chemical contamination, or oxidation of the connecting surfaces. Fuse holders within enclosures that are not considered active and subject to mechanical stress, fatigue and electrical transients will be included in the Fatigue-Monitoring Program(B.2.4).

The staff reviewed the applicant’s response to POI-1(c) regarding whether fuse holders within the enclosures are considered active and whether they are subject to stress and fatigue. The staff discussed this issue with the applicant. The applicant believed that there are no fuse holders that would fall within the definition of being in an outside environment that would need aging management review, but was not sure. The staff was still unclear regarding the aging management of fuse holders. ISG-5, “Identification and Treatment of Electrical Fuse Holders,” which discusses scoping, screening, and aging management of fuse holders, states that fuse holders inside the enclosure of an active component, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards, are considered to be piece parts of the larger assembly, and thus 10 CFR 54.21 considers them outside the scope for license renewal. The staff requested that the applicant make a positive statement that all fuse holders are within active enclosures and hence are not within scope and need not be subject to an AMR. If the applicant cannot make this statement, the staff requested that the applicant clarify how fuse holders within the scope of license renewal and subject to an AMR will be managed during the period of extended operation. The staff was also concerned that the applicant may have missed fuse holders which are used in circuits to isolate safety loads from non-safety loads. The staff requested that the applicant investigate and confirm whether any fuse holders fall into this category. These issues were identified as Open Item 3.6.2.4.5.2-1.

By letter dated July 7, 2003, the applicant clarified that fuse blocks (fuse holders) at FCS are either in active components (panels, switchgear, or cabinets), which are outside the scope of license renewal, or are in enclosures (junction boxes) that are in controlled environments. The applicant stated that it will manage the aging of fuse holders in accordance with ISG-5.

Further, the applicant clarified that FCS does not have any fuse holders in circuits used to isolate safety loads from non-safety loads that are in areas of environmental extremes or that are subject to aging management.

On the basis of the applicant's response to Open Item 3.6.2.4.5.2-1, the staff concludes that the applicant has clarified which fuse holders are within scope and has clarified that management of fuse holders within the scope of license renewal and subject to an AMR will be done in accordance with ISG-5. The staff finds this acceptable. Finally, the applicant has clarified that there are no fuse holders that are used to isolate safety and non-safety loads that are subject to an AMR. The staff finds this acceptable. On this basis, Open Item 3.6.2.4.5.2-1 is closed.

4.7.2.2-1 The staff has evaluated the information provided by the applicant in its LRA and in its response to RAI 4.7.2-1. The staff has concluded that the applicant appropriately identified those TLAAs (fatigue crack growth, aging of cast austenitic stainless steel (CASS) RCS piping and components, and primary water stress-corrosion cracking (PWSCC) of Inconel 82/182 RCS welds), which may impact the extension of the applicant's existing leak before break (LBB) analysis through the period of extended operation. The applicant has committed to perform a plant-specific LBB analysis prior to entering the period of extended operation which will address these TLAAs and project the analysis to the end of the period of extended operation. However, the applicant's commitment did not appear to meet 10 CFR 54.21(c)(1) which requires the applicant to demonstrate that (i) the analysis remains valid for the period of extended operation, (ii) the analysis has been projected to the end of the period of extended operation, or (iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff requested that the applicant provide the information needed for the staff to determine whether (i) the applicant's LBB analysis remains valid for the period of extended operation, (ii) the applicant's LBB analysis has been projected to the end of the period of extended operation, or (iii) the effects of aging on the intended function(s) of the components within the scope of the LBB analysis will be adequately managed for the period of extended operation. This was identified as Open Item 4.7.2.2-1.

NEI 95-10, Revision 3, provides guidance to applicants who apply for renewal of their operating licenses. In Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," the staff has endorsed this NEI guideline. Section 5.1.4 of NEI 95-10 allows for deferral of TLAA evaluations. The guidance states that, if an applicant decides to defer the completion of an evaluation, it should submit additional information to the staff to support a conclusion that the effects of aging addressed in the TLAA will be adequately managed. This information includes (1) details of the methodology that will be used for the TLAA evaluation, (2) the acceptance criteria that will be used to judge the adequacy of the structure or component, consistent with the CLB, when the TLAA evaluation or analysis is performed, (3) the corrective actions that will be performed to provide reasonable assurance that the structure or component will perform its intended function or will not be outside of its design basis established by the CLB, and (4) information to identify when the completed TLAA evaluation will be submitted to ensure that the evaluation will be performed before the structure or component will be unable to perform its intended function.

By letter dated July 7, 2003, the applicant stated that it will defer completion of the plant-specific LBB evaluation in accordance with Section 5.1.4 of NEI 95-10. The applicant submitted the information below, as provided in NEI 95-10.

- The applicant committed to complete a plant-specific LBB evaluation of the RCS piping using the latest LBB criteria. The LBB analysis will incorporate the effects of thermal aging, plant-specific materials, operating temperatures/pressures, loads at welds in the primary loops, and weld fabrication. The plant-specific methodology will also use the existing plant's RCS leak detection capability and the piping stress analysis loads for the FCS RCS configuration. The analysis will be applicable for the period of extended operation, and will use a methodology from the Westinghouse Electric Company for thermal aging considerations. Westinghouse has performed over 30 plant-specific LBB analyses approved by the NRC, and addressed thermal aging effects of the cast materials as applicable. For the primary loop piping, the latest LBB SER which includes the Westinghouse analysis methodology was for D.C. Cook Units 1 and 2. This SER was issued in December 1999 (docket numbers 50-315 and 50-316).

The staff reviewed this information and finds that it adequately describes the methodology that will be used for the applicant's LBB analysis.

- Acceptance criteria used to determine the adequacy of the structure or component when the LBB analysis is performed will be in accordance with draft Standard Review Plan (SRP) 3.6.3, "Leak-Before-Break Evaluations Procedures," published for comment in Volume 52, Number 167 of the *Federal Register*, dated, Friday, August 28, 1987, and NUREG-1061, Volume 3.

The staff reviewed this information and finds that the applicant has identified the acceptance criteria that will be used to judge the adequacy of the structures or components when the LBB analysis is performed.

- The plant-specific LBB analysis will include evaluation of corrective actions that can be performed to provide reasonable assurance that the component in question will perform its intended function when called upon, or will not be outside of its design basis established by the plant's CLB. One such corrective action is to maintain the CLB RCS leak rate program as defined in FCS Technical Specification (TS) 2.1.4 during the period of extended operation. The leak detection capability of the systems noted in TS 2.1.4 meet the intent of Regulatory Guide 1.45 and will be capable of performing their designed function during the period of extended operation.

The staff reviewed this information and finds that the applicant has identified the corrective actions it will perform to ensure that the structures and components will continue to perform their intended functions.

- The applicant committed to submit a License Amendment Request containing the plant-specific LBB evaluation described above to the NRC no later than December 2006, which is well before the period of extended operation. This submittal schedule supports the applicant's planning decisions for possible changes to RCS operation or configuration.

The staff reviewed this information and finds that the applicant has identified the submittal date for the LBB analysis. Further, the staff concludes that this submittal date should provide sufficient time to address aging issues before loss of intended function of the applicable SCs.

On the basis of the applicant's response to Open Item 4.7.2.2-1, the staff concludes that the applicant has followed the guidance to support the deferral of the submittal of its LBB analysis. The characteristics of the LBB analysis, as proposed by the applicant, is sufficient to allow the staff to determine whether the analysis, when submitted, is adequate to demonstrate that the analysis has been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii). Open Item 4.7.2.2-1 is closed.

4.7.4-1 The application did not initially discuss an Alloy 600 repair in the temperature nozzle in the pressurizer lower shell. This was identified as new Open Item 4.7.4-1. As a result of discussions between the staff and the applicant, the applicant, in a letter dated July 7, 2003, added a new Section 4.7.4 to the license renewal application. This section indicates that the temperature nozzle in the pressurizer lower shell was repaired by adding a weld pad to the existing weld build-up to the lower shell outer diameter (OD) and welding this pad to the existing nozzle. This moved the pressure boundary from the inner diameter to this location. The Alloy 600 J-weld and original crack were left in place at the inside surface of the pressurizer as part of the repaired configuration.

In a letter dated October 25, 2000, Westinghouse provided Omaha Public Power District (OPPD) the technical justification for the weld on the liquid space Alloy 600 instrument nozzle on the OD of the pressurizer. This letter stated that the subject repair should be made in accordance with later editions of Section III, or the 1992 Edition (or later) of Section XI.

In April 2002, Westinghouse notified OPPD that its technical justification of October 2000 only considered the effects of the repair on the requirements of ASME Section III, and did not consider the Section XI requirements related to leaving the flaw in place after the repair was completed and the vessel returned to service.

In April 2003, OPPD received the "calculation note" titled "Evaluation of Fatigue Crack Growth of Postulated Flaw at Omaha Fort Calhoun Pressurizer Lower Shell Instrumentation Nozzle," dated January 8, 2003, that evaluated the Section XI requirements related to leaving the flaw in place after the repair was completed and the vessel returned to service.

OPPD has evaluated the crack, and any potential future growth of the crack, and determined it does not impact the structural integrity of the vessel for the current licensed 40-year life. OPPD has elected to defer completion of the evaluation that demonstrates that the crack, and any potential future growth of the crack, does not impact the structural integrity of the vessel for the period of extended operation. On the basis of guidance in Section 5.1.4 of NEI 95-10, Revision 3, the applicant provided details to explain how the effects of aging will be addressed for this evaluation.

OPPD will submit, for staff review and approval, the fracture mechanics evaluation of the small-bore instrument nozzle J-weld region at the repaired instrument nozzle for the period of extended operation. This submittal will be made prior to entering the period of extended operation. This evaluation will include bounding the flaw size by the size of the J-weld itself, and addressing the possibility of corrosion in the presence of a flaw.

10 CFR 54.3 contains six criteria that must be satisfied for an analysis to be considered a time-limited aging analysis (TLAA). As a result of the information submitted in its July 7, 2003 letter, the applicant's evaluation of flaw growth for a crack that was left in place at the inside surface of the pressurizer and the impact of corrosion on the pressurizer nozzle meet these six criteria and should be considered a TLAA.

Section 5.1.4 of NEI 95-10, Revision 3, indicates that an applicant who elects to defer completing the evaluation of a TLAA at the time of a renewal application should submit the following details in the renewal application to support a conclusion that the effects of aging addressed by that TLAA will be managed for a specific structure or component:

- Details concerning the methodology which will be used for TLAA evaluation,

- Acceptance criteria that will be used to judge the adequacy of the structure or component, consistent with the CLB, when the TLAA evaluation or analysis is performed,

- Corrective actions that the applicant could perform to provide reasonable assurance that the component in question will perform its intended function when called upon, or will not be outside of its design basis established by the plant's CLB, and

- Identification of when the completed TLAA evaluation will be submitted to ensure that the necessary evaluation will be performed before the structure or component in question would not be able to perform its intended functions established by the CLB.

The July 7, 2003 letter contains a methodology and criteria for evaluating the impact of flaw growth on the original crack that was left in place at the inside surface of the pressurizer and specifies that the impact of corrosion will be included in the evaluation. The methodology is summarized as follows:

1. Design drawings are reviewed to determine vessel, nozzle and J-weld dimensions and materials.

2. The initial flaw size to be used in the evaluation is calculated.

3. Manufacturing records are reviewed to determine the reference temperature (RT_{NDT}) of the base metal at the location of interest.

4. Design operation transients are reviewed to determine their appropriateness for use in the generation of stresses for use in the flaw analysis.

5. When the design transients are not appropriate, a realistic bounding transient is developed for analysis purposes.

6. Thermal transient analyses are performed to determine through-wall temperatures for use in the stress analysis.

7. Stress analyses are performed at various time points during each plant operating event of interest.

8. Pressure and mechanical load stresses are calculated.

9. A survey of the combined pressure, thermal, and mechanical stresses is conducted to determine the limiting time point for evaluation.

10. Stresses are determined to calculate the applied stress intensity factor, K_I.

11. The applied stress intensity factor is calculated for comparison to allowable values.

12. Fatigue crack growth of the flaw is calculated over the 60 years.

13. The final flaw size is used to confirm flaw stability over the remaining life of the plant.

14. The flaw stability checks defined above are performed for normal and upset conditions and emergency and faulted conditions using the respective allowables defined per ASME Section XI.

15. Primary stress limits per NB-3000 are checked considering the effect of the final flaw size.

This methodology is acceptable because it will determine the impact of plant operation, design transients, material fracture resistance, and flaw growth on pressurizer integrity for the period of extended operation.

The flaw will be acceptable if it satisfies the linear elastic fracture mechanics criteria in ASME Code Section XI, IWB-3611 or IWB-3612, or elastic-plastic fracture mechanics criteria in ASME Code Section XI, Appendix K, articles K-2200, K-2300, and K-2400. Since the acceptance criteria are in accordance with ASME Code criteria, they are acceptable for use in this TLAA.

By limiting pressure and the maximum rate of decrease in temperature for the pressurizer, the corrective action will limit the stresses on the flaw remaining in the pressurizer and provides reasonable assurance that the component in question will perform its intended function when called upon or will not be outside of the design basis established by the plant’s CLB.

The applicant indicates that the TLAA for this issue will be completed before the period of extended operation and the analyses will be submitted for staff review and approval.

By satisfying the criteria in Section 5.1.4 of NEI 95-10, Revision 3, the staff concludes that the applicant has provided a methodology and criteria for assuring that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation and has satisfied the TLAA criteria 10 CFR 54.21(c)(1)(iii). The applicant's commitment to complete the evaluation is documented in Appendix A of this SER.

The applicant's corrective action includes assuring that the pressure at any temperature should not be any higher than the higher of the following two limits:

1. The saturation pressure plus 200 psi, and

2. 350 psi and the maximum rate of temperature decrease is 200 ^{o}F/hr.

On the basis of the staff's evaluation described above, the summary description for the "Pressurizer Alloy 600 J-Weld Left in Place" described in the USAR Supplement (LRA, Appendix A.3.6.4) is acceptable. Open Item 4.7.4-1 is closed.

1.6 Summary of Confirmatory Items

Confirmatory items are items for which the staff and the applicant have reached a satisfactory resolution, but the resolution has not yet been formally submitted to the staff.

As a result of its review of the LRA for FCS, including additional information submitted to the NRC through August 7, 2003, the staff identified the following confirmatory items. An issue was confirmatory if the staff and applicant had agreed on a resolution to an the issue, but the applicant had not yet formally provided the resolution for staff review. Each confirmatory item was assigned a unique identifying number.

<u>Item</u> <u>Description</u>

2.1.3.1.2-1 As part of its review of the implementation and results of the applicant's scoping activities, the staff performed a license renewal scoping and screening inspection at the FCS site during the week of November 8, 2002, and an inspection of the applicant's AMPs during the weeks of January 6 and January 20, 2003. The inspectors reviewed the applicant's engineering evaluations, documentation of the portions of the systems added to scope, and selected layout markup drawings. The inspectors also discussed the process with the cognizant individuals responsible for the evaluations. Additionally, the NRC inspectors performed walkdowns of selected areas of the plant containing SSCs of interest. The inspection team identified one item which should be considered by the applicant for inclusion within scope based on the 10 CFR 54.4(a)(1) criterion. Inspection Open Item 50-285/02-07-02 identified unqualified safety injection tank level and pressure indicators that should be considered in the scope of license renewal. These indicators are used to ensure that assumptions are met for the mitigation analysis for a LOCA. The applicant reviewed this issue and committed to include these components within scope. This was identified as Confirmatory Item 2.1.3.1.2-1.

By letter dated July 7, 2003, the applicant included the safety injection tank level and pressure indicators in scope. The applicant noted that these components were subsequently screened out as active components, resulting in no changes to the LRA. The staff finds the applicant's inclusion of the components within the scope of license renewal and the screening out of the components as active to be acceptable. Confirmatory Item 2.1.3.1.2-1 is closed.

3.0.3.12.2-1 During the staff's AMR inspection, the applicant committed to revise the general corrosion of external surfaces program to include the spent fuel pool cooling system. This was identified as Confirmatory Item 3.0.3.12.2-1.

By letter dated July 7, 2003, the applicant made the revision, noting that the spent fuel pool heat exchanger is the only system component within scope that is fabricated from carbon steel. All other system components are fabricated from stainless steel. Therefore, the heat exchanger shell requires external surface aging management for loss of material.

On the basis of the applicant's revision to the general corrosion of external surfaces program, the staff concludes that the AMP will provide adequate aging management for the components of the spent fuel pool cooling system. Confirmatory Item 3.0.2.12.2-1 is closed.

4.3.2-1 Section 4.3.2 of the LRA contained a discussion of the proposed AMP to address fatigue of the FCS pressurizer surge line. The discussion indicated that the AMP will consist of an inspection program. The LRA also indicated that the results of the surge line inspections will be used to assess the appropriate approach for addressing environmentally-assisted fatigue of the surge lines. However, Section 4.3.3 of the LRA indicated that a reevaluation of the fatigue usage of critical areas of the surge line will be performed prior to the period of extended operation and that the bounding locations will be included in the Fatigue Monitoring Program (FMP). In RAI 4.3.2-3, the staff requested that the applicant describe how the effect of the reactor water environment will be considered in the reevaluation of the critical areas of the surge line and how the results of this evaluation will be monitored by the FMP.

The applicant's December 19, 2002, response indicated that the limiting surge line welds would be inspected prior to the period of extended operation. The applicant further indicated that the results of these inspections will be used to assess the appropriate approach for addressing environmentally-assisted fatigue of the surge lines. The applicant indicated that the approach would include one or more of the following four options.

1. further refinement of the fatigue analysis to lower the Cumulative Usage Factor (CUF) to below 1.0
2. repair of the affected locations
3. replacement of the affected locations
4. management of the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC)

The applicant committed that, if Option 4 were to be selected, it will provide the inspection details, including scope, qualification method, and frequency, to the NRC staff for review and approval prior to the period of extended operation. An AMP under this option would be a departure from the design basis CUF evaluation described in the USAR Supplement, and therefore would require a license amendment pursuant to 10 CFR 50.59. This was identified as Confirmatory Item 4.3.2-1.

By letter dated July 7, 2003, the applicant formalized this commitment. The staff finds this acceptable. Confirmatory Item 4.3.2-1 is closed.

4.3.2-2 Section 4.3.4 of the LRA contained a discussion of the analysis of Class II and III components at FCS. American National Standards Institute (ANSI) B31.1 requires that a reduction factor be applied to the allowable bending stress range if the number of full-range thermal cycles exceeds 7000. The LRA indicated that the United States of America Standards (USAS) B31.1 limit of 7000 equivalent full-range cycles may be exceeded during the period of extended operation for the sampling system and that the affected portions of the NSSS sampling system would be tracked by the FMP. In RAI 4.3.4-1, the staff requested that the applicant provide the calculated thermal stress range for these affected portions of the NSSS sampling system.

The applicant's December 12, 2002, response indicated that the small bore piping at FCS was designed and supported based on nomographs developed in accordance with the USAS B31.1 code. As a consequence, there were no specific stress calculations. The applicant committed that, as part of the FMP, the sampling piping will be analyzed and a stress calculation performed to determine the thermal stress range for the line. The applicant should confirm that the results, when completed, will meet USAS B31.1. This was identified as Confirmatory Item 4.3.2-2.

By letter dated July 7, 2003, the applicant formalized this commitment and confirmed that the stress calculation results for the small bore sampling system piping, when completed, will meet USAS B31.1 requirements. The staff finds this acceptable. Confirmatory Item 4.3.2-2 is closed.

1.7 Summary of Proposed License Conditions

As a result of the staff's review of the FCS application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified two proposed license conditions. The first license condition requires the applicant to include the USAR Supplement in the next USAR update required by 10 CFR 50.71(e) following issuance of the renewed license. The second license condition requires that the future inspection activities identified in the USAR Supplement be completed prior to the period of extended operation.