Safety Evaluation Report

Related to the License Renewal of the Brunswick Steam Electric Plant, Units 1 and 2

Docket Nos. 50-325 and 50-324

Carolina Power & Light Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

December 2005

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Brunswick Steam Electric Plant (BSEP), Units 1 and 2, license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff). By letter dated October 18, 2004, Carolina Power & Light Company (CP&L or the applicant) submitted the LRA for BSEP in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54). CP&L is requesting renewal of the operating licenses for BSEP Units 1 and 2, (Facility Operating License Numbers DPR-71 and DPR-62, respectively) for a period of 20 years beyond the current expiration dates of midnight September 8, 2016, for Unit 1 and midnight December 27, 2014, for Unit 2.

The BSEP units are located south of Wilmington, NC, at the mouth of the Cape Fear River in Brunswick County, NC, and two miles north of Southport, NC. The NRC issued the construction permits for Units 1 and 2 on February 7, 1970. The NRC issued the operating licenses for Unit 1 on November 12, 1976; and for Unit 2 on December 27, 1974. Units 1 and 2 are boiling water reactors (BWRs) with primary containments of the BWR Mark I design. Each unit has a nuclear steam supply system that is supplied by General Electric (GE) Nuclear Energy Company. The balance of the plant was originally designed and constructed by Brown & Root with the assistance of its agent, United Engineers & Constructors. Each unit operates at a licensed power output of 2923 megawatt thermal (Mwt), with a gross electrical output of approximately 1007 megawatt electric (Mwe).

This SER presents the status of the staff's review of information submitted to the NRC through December 6, 2005, the cutoff date for consideration in the SER. The staff will present its final conclusion on the review of the BSEP application in its update to this SER.

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ABBREVIATIONS

AC	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductor steel reinforced
ADS	automatic depressurization system
AERM	aging effects requiring management
AFFF	aqueous fire fighting foam
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
AMP	aging management program
AMR	aging management review
AMSAC	ATWS mitigating system actuation circuitry
ANSI	American National Standards Institute
AOG	augmented off-gas/auxiliary off-gas
AOO	anticipated operational occurrence
API	American Petroleum Institute
APRM	average power range monitor
ARI	alternate rod injection/alternate rod insertion
ARM	area radiation monitor
ART	adjusted reference temperature
AS&CR	auxiliary steam and condensate recovery
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
AST	accident source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
ATWS-RPT	anticipated transient without scram–recirculation pump trip
AWS	American Welding Society
AWWA	American Water Works Association
B&PV	boiler and pressure vessel
BNP	Brunswick Nuclear Plant
BSEP	Brunswick Steam Electric Plant
BTP	branch technical position
BTRS	boron thermal regeneration system
BWR	boiling water reactor
BWROG	Boiling Water Reactor Owners Group
BWRVIP	Boiling Water Reactor Vessel and Internals Program
CAC	containment atmospheric control
CAD	containment atmosphere dilution
CAP	Corrective Action Program
CASS	cast austentitic steel
CB	control board

CCW	closed cooling water or component cooling water
CDD	condensate deep bed demineralizer
CDF	core damage frequency
CET	core exit thermocouple
CF	chemistry factor
CFD	condensate filter demineralizer
CFR	*Code of Federal Regulations*
CHRS	containment heat removal system
CI	confirmatory item
CL	chlorination
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CP&L	Carolina Power & Light Company, a Progress Energy Company
CR	condition report
CRD	control rod drive
CRDH	control rod drive housing
CRDM	control rod drive mechanism
CRGT	control rod guide tube
CRW	clean radioactive waste
CS	containment spray or carbon steel
CST	condensate storage tank
CUF	cumulative usage factor
CVCS	chemical and volume control system
CW	circulating water
DBA	design-basis accident
DBE	design-basis event
DC	direct current
DG	diesel generator
DGB	diesel generator building
DOR	Division of Operating Reactors (NRC)
D/P	differential pressure
DRW	dirty radioactive waste
DSCSS	drywell and suppression chamber spray system
DW	demineralized water
DWT	demineralized water tank
ECCS	emergency core cooling system
EDB	equipment database
EDG	emergency diesel generator
EFPY	effective full-power year
EOL	end of life
EPRI	Electric Power Research Institute
EQ	environmental qualification
ESF	engineered safety feature
FAC	flow-accelerated corrosion
F_{en}	environmental fatigue factor
FERC	Federal Energy Regulatory Commission

FHA	fire hazards analysis
FO	fuel oil
FOL	facility operating license
FOST	fuel oil storage tank
FP	fire protection
FPP	fire protection plan
FSAR	Final Safety Analysis Report
FSD	functional system description
FSER	Final Safety Evaluation Report
FW	feedwater
GALL	generic aging lessons learned
GDC	general design criteria or general design criterion
GE	General Electric
GEIS	generic environmental impact statement
GL	generic letter
GSI	general safety issue
HAZ	heat-affected zone
HCU	hydraulic control unit
HD	heater drains
HDFSS	high density fuel storage system
HELB	high-energy line break
HE/ME	high energy/moderate energy
HEPA	high efficiency particulate air
HJTC	heated junction thermocouple
HMWPE	high molecular weight polyethylene
HP	high pressure
HPCI	high pressure coolant injection
HPCS	high pressure core spray (not an applicable system for BSEP)
HVAC	heating, ventilation, and air conditioning
HWC	hydrogen water chemistry
HX	heat exchanger
IA	instrument air
IAN	non-interruptible instrument air
IASCC	irradiation assisted stress corrosion cracking
I&C	instrumentation and control
ID	inside diameter
IE	inspection and enforcement (former NRC Office of Inspection and Enforcement)
IEEE	Institute of Electrical and Electronics Engineers
IGA	intergranular attack
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test (containment type A test)
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IPCEA	Insulated Power Cable Engineers Association
IR	insulation resistance

IRM	intermediate range monitor
ISG	interim staff guidance
ISI	inservice inspection
KV	kilovolt
LBB	leak before break
LER	Licensee Event Report
LO	lubricating oil
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LP	low pressure
LPCI	low pressure coolant injection
LPCS	low pressure core spray
LPRM	local power range monitor
LR	license renewal
LRA	license renewal application
M-1	intended function (pressure boundary)
M-2	intended function (filtration)
M-3	intended function (flow restriction)
M-4	intended function (structural support/seismic integrity)
M-5	intended function (heat transfer)
MCB	main control board
MEAP	**material, environment, aging program**
MeV	million electron volts
MIC	microbiologically induced corrosion
MOD	motor operated disconnect
MS	main steam
MSIV/LCS	main steam isolation valve/leakage control system
MSL	main steam line or mean sea level
MSLB	main steam line break
MSR	moisture separator reheater
MVD	miscellaneous vents and drains
Mwe	megawatt electric
Mwt	megawatt thermal
MWTS	makeup water treatment system
NDE	nondestructive examination
NDTT	nil-ductility transition temperature
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act of 1969
NFPA	National Fire Protection Association
Ni	nickel
NMS	neutron monitoring system
NPAR	nuclear plant aging research
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NSR	non-safety-related

NSSS	nuclear steam supply system
NUREG	designation of publications prepared by the NRC staff
OBE	operating-basis earthquake
ODSCC	outside-diameter stress-corrosion cracking
OE	operating experience
OI	open item
OLTP	original licensed thermal power
OPRM	oscillation power range monitor
PASS	post-accident sampling system
PBDS	period based detection system
PCB	power circuit breaker
PCS	primary containment structure
PEC	Progress Energy Carolinas
PFM	probabilistic fracture mechanics
pH	concentration of hydrogen ion
P&ID	piping and instrumentation diagram
PM	preventive maintenance
PNS	pneumatic nitrogen system
PORV	power-operated relief valve
PRF	penetration room filtration
PRM	process radiation monitoring
PSRF	non-safety-related that can prevent a safety-related function
P-T	pressure-temperature
PTLR	pressure-temperature limits report
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PW	pipe whip
PWS	potable water system
PWSCC	primary water stress-corrosion cracking
QA	quality assurance
RAI	request for additional information
RB	reactor building
RBCCW	reactor building closed cooling water
RBM	rod block monitor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RFP	reactor feedwater pump
RG	regulatory guide
RHR	residual heat removal
RI	risk informed
RI-ISI	risk-informed inservice inspection
RMCS	reactor manual control system
RMS	radiation monitoring system

RMWST	reactor makeup water storage tank
RNA	reactor non-interruptible air
RPIS	rod position information system
RPS	reactor protection system
RPV	reactor pressure vessel
RT_{NDT}	reference temperature nil-ductility transition
$RT_{NDT(U)}$	reference temperature nil-ductility transition (unirradiated)
RT_{PTS}	reference temperature pressurized thermal shock
RTS	reactor trip system
RVI	reactor vessel internals
RVLIS	reactor vessel instrumentation system
RWCU	reactor water cleanup system
RWM	rod worth minimizer
RWST	refueling water storage tank
RXS	reactor building sampling system
SA	service air
SAT	startup auxiliary transformer
SBO	station blackout
SC	structure and component or suppression chamber
SCC	stress-corrosion cracking
SCW	screen wash water
SDV	scram discharge volume
SE	safety evaluation
SER	Safety Evaluation Report
SFP	spent fuel pool
SGBD	steam generator blowdown
SGTS	standby gas treatment system
SI	safety injection
SJAE	steam jet air ejector
SLC	standby liquid
SLMS	stator leak monitoring system
SMP	structural monitoring program
SOC	statement of consideration
SPDS	safety parameter display system
SR	safety-related
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SRV	safety relief valve
SS	stainless steel
SSC	system, structure, and component
SSE	safe-shutdown earthquake
SW	service water
SWIS	service water intake structure
TAC	technical assignment control (internal NRC work management tool)
TASCS	thermal stratification, cycling, and striping

TB	turbine building
TBCCW	turbine building closed cooling water
TGSCC	trans-granular stress corrosion cracking
TID	total integrated does
TIP	traversing incore probe
TLAA	time-limited aging analysis
TPNS	total plant numbering system
TS	technical specification
TSC	technical support center
TSP	trisodium phosphate
TT	thermal transients
UAT	unit auxiliary transformer
UFSAR	updated final safety analysis report
USAS	United States of America Standards
USE	upper-shelf energy
UUSE	unirradiated upper shelf energy
UT	ultrasonic test
VAC	Volts alternating current
VDC	Volts direct current
VFLD	vessel flange leak detection
WANO	World Association of Nuclear Operators
WCAP	Westinghouse Commercial Atomic Power (report)
WOG	Westinghouse Owners Group
XLPE	cross-linked polyethylene

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SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for the Brunswick Steam Electric Plant (BSEP), as filed by Carolina Power & Light Company (CP&L or the applicant). By letter dated October 18, 2004, CP&L submitted its application to the U.S. Nuclear Regulatory Commission (NRC or the Commission) for renewal of the BSEP operating licenses 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 BSEP license renewal review is S.K. Mitra. Mr. Mitra can be contacted by telephone at 301-415-2783 or by electronic mail at skm1@nrc.gov. Alternatively, written correspondence may be sent to the following address:

License Renewal and Environmental Impacts Program
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
Attention: S.K. Mitra, Mail Stop 0-11 F1

In its October 18, 2004, submittal letter, the applicant requested renewal of the operating licenses issued under Section 104b (Operating License Nos. DPR-71 and DPR-62) of the Atomic Energy Act of 1954, as amended, for BSEP Units 1 and 2 for a period of 20 years beyond the current license expiration dates of midnight September 8, 2016, for Unit 1 and midnight December 27, 2014, for Unit 2. The BSEP units are located south of Wilmington, NC, at the mouth of the Cape Fear River in Brunswick County, NC, and two miles north of Southport, NC. The NRC issued the construction permits for Units 1 and 2 on February 7, 1970. The staff issued the operating licenses for Unit 1 on November 12, 1976; and for Unit 2 on December 27, 1974. Units 1 and 2 are boiling water reactors (BWRs) with primary containments of the BWR Mark I design. Each unit has a nuclear steam supply system that is supplied by General Electric Nuclear Energy Company. The balance of the plant was originally designed and constructed by Brown & Root with the assistance of its agent, United Engineers & Constructors. Each unit operates at a licensed power output of 2923 megawatt thermal (Mwt), with a gross electrical output of approximately 1007 megawatt electric (Mwe). The updated final safety analysis report (UFSAR) contains details concerning the plant and the site.

The license renewal process consists of two concurrent reviews - a technical review of safety issues and an environmental review. The NRC regulations found in 10 CFR Parts 54 and 51, respectively, set forth the requirements for these reviews. The safety review for the BSEP license renewal is based on the applicant's LRA and on the responses to the staff's requests for additional information (RAIs). The applicant supplemented and clarified its responses to the LRA and RAIs in audits, meetings, and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through December 6, 2005. The staff reviewed the information received after that date on a case-by-case basis, depending on the stage of the safety review and the volume and complexity of the information. The public may view the LRA and all pertinent information and materials, including those mentioned above, at the NRC Public Document Room, located in One White Flint North, 11555 Rockville Pike (first floor), Rockville, MD, 20852-2738 (301-415-4737/800-397-4209), and at the William Madison Randal Library, 601 S. College Road, Wilmington, NC, 28403-3201. In addition, the public may find the BSEP Units 1 and 2 LRA, as well as materials related to the license renewal review, on the NRC website at www.nrc.gov.

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

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

SER Appendix A is a table that identifies the applicant's commitments associated with the renewal of the operating licenses. SER Appendix B provides a chronology of the principal correspondence between the staff and the applicant related to the review of the application. SER Appendix C is a list of principal contributors to the SER. SER Appendix D is a bibliography of the references used in support of the review.

In accordance with 10 CFR Part 51, the staff prepared a draft plant-specific supplement to the Generic Environmental Impact Statement (GEIS). This supplement discusses the environmental considerations related to renewing the licenses for Units 1 and 2. The NRC staff issued draft Supplement 25 to NUREG-1437 "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Brunswick Steam Electric Plant, Units 1 and 2 Final Report," on August 30, 2005.

1.2 <u>License Renewal Background</u>

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, rather than 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 anticipated interest in license renewal and held a workshop on nuclear power plant aging. This workshop led the NRC to establish a comprehensive program plan for nuclear plant aging research. 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 gain experience necessary to develop 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 may also manage plant-aging phenomena. As a result, the NRC amended the license renewal rule in 1995. 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, the NRC amended 10 CFR Part 54 to focus on managing the adverse effects of aging rather than on identifying age-related degradation unique to license renewal. The NRC initiated these rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the revised Rule clarified and simplified the integrated plant assessment (IPA) process 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 and developed an amendment to 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal and fulfill 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 SSCs, as well as a few other safety-related (SR) issues, 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 including those SSCs (1) that are safety-related (SR), (2) whose failure could affect SR functions, and (3) that are relied on to demonstrate compliance with the NRC's regulations for fire protection (FP), environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), an applicant for a renewed license must review all SSCs that are within the scope of the Rule to identify SCs that are subject to an aging management review (AMR). Those SCs that are subject to an AMR perform an intended function without moving parts or without a change in configuration or properties, and 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(s) of those SCs will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation; however, active equipment is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging that may affect active equipment are more readily detectable and can be identified and corrected through routine surveillance, performance monitoring, and maintenance activities. The surveillance and maintenance activities programs for active equipment, as well as other aspects of maintaining the plants' design and licensing basis, are required throughout the period of extended operation.

Pursuant to 10 CFR 54.21(d), each LRA is required to include a supplement to the UFSAR. This supplement must contain a summary description of the applicant's programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

License renewal also requires the identification and updating of the TLAAs. During the design phase for a plant, certain assumptions are made about the length of time the plant can operate. These assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must either show that these calculations will remain valid for the period of extended operation, project the analyses to the end of the period of extended operation, or demonstrate that the effects of aging on these SSCs can 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 RG endorses the Nuclear Energy Institute (NEI), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, March 2001 (NEI 95-10). NEI 95-10 details an acceptable method of implementing the license renewal rule. The NRC also used the SRP-LR to review this application.

In the LRA, BSEP fully utilizes the process defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," issued in July 2001. The GALL Report provides the staff with a summary of staff-approved aging management programs (AMPs) for the aging of many 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 can 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. The report also serves as a reference for both applicants and staff reviewers to quickly identify those AMPs and activities that the staff has determined can provide adequate aging management during the period of extended operation.

1.2.2 Environmental Review

In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared a "Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants" (NUREG-1437, Revision 1) to document its evaluation of 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 codified in 10 CFR Part 51, Appendix B to Subpart A. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of those environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

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 the GEIS did not consider. As part of its scoping process, the NRC held a public meeting on January 27, 2005, in Southport, NC, to identify environmental issues specific to the plant. The staff's draft plant-specific Supplement 25 to the GEIS, which was issued on August 30, 2005, documents the results of the environmental review and includes a preliminary recommendation with respect to the license renewal action. The staff held another public meeting on October 18, 2005, in Southport, North Carolina, to discuss the draft plant-specific Supplement 25 to the GEIS. After considering comments on the draft, the staff will prepare and publish a final, plant-specific supplement to the GEIS separately from this report.

1.3 Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54). The staff performed its technical review of the BSEP LRA in accordance with NRC guidance and the requirements of 10 CFR Part 54. The standards for renewing a license are set forth in 10 CFR 54.29. This SER describes the results of the staff's safety review.

In 10 CFR 54.19(a), the NRC requires a license renewal applicant to submit general information. The applicant provided this general information in LRA Section 1 for BSEP, Units 1 and 2, which it submitted to the staff by letter, dated October 18, 2004. The staff reviewed LRA Section 1 and found that the applicant had submitted the information required by 10 CFR 54.19(a).

In 10 CFR 54.19(b), the NRC requires that each LRA 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 stated the following in the LRA regarding this issue:

> The current indemnity agreement for BSEP 1 and 2 states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire. Item 3 of the Attachment to the indemnity agreement, as amended, lists BSEP 1 and 2 Operating Licenses DPR-71 and DPR-62. The Company requests that conforming changes be made to the indemnity agreement, and/or the Attachment to the agreement, as required, to specify the extension of the agreement until the expiration date of the renewed BSEP 1 and 2 operating licenses as sought in this application.

The staff intends to maintain the original license numbers upon issuance of the renewed licenses, if approved. Therefore, conforming changes to the indemnity agreement do not need to be made, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the NRC requires that each LRA must contain: (a) an integrated plant assessment (IPA), (b) a description of any CLB changes that occurred during the staff review of the LRA, (c) an evaluation of TLAAs, and (d) a UFSAR supplement. LRA Sections 3 and 4 and Appendix B address the license renewal requirements of 10 CFR 54.21(a), (b), and (c). LRA Appendix A contains the license renewal requirements of 10 CFR 54.21(d).

In 10 CFR 54.21(b), the NRC requires that each year following submission of the LRA, and at least three months before the scheduled completion of the staff's review, the applicant must submit an amendment to the renewal application that identifies any changes to the CLB of the facility that materially affect the contents of the LRA, including the UFSAR supplement. The applicant submitted an update to the LRA by letter dated September 29, 2005, which summarized the changes to the CLB that have occurred at BSEP, Units 1 and 2, during the staff's review of the LRA. This submission satisfies the requirements of 10 CFR 54.21(b) and is still under staff review.

In accordance with 10 CFR 54.22, an applicant's LRA must include changes or additions to the technical specifications that are necessary to manage the effects of aging during the period of extended operation. In Appendix D to the LRA, the applicant stated that it had not identified any technical specification changes necessary to support issuance of the renewed operating licenses for Units 1 and 2. This adequately addresses the requirement specified in 10 CFR 54.22.

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

As required by 10 CFR 54.25, the ACRS will issue a report to document its evaluation of the staff's LRA review and associated SER. SER Section 5 will incorporate the ACRS report once it is issued. SER Section 6 will document the findings required by 10 CFR 54.29.

The final plant-specific supplement to the GEIS will document the staff's evaluation of the environmental information required by 10 CFR 54.23 and will specify the considerations related to renewing the licenses for Units 1 and 2. The staff will prepare this supplement separately from this SER.

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 regulatory burden, and increasing public confidence. Interim staff guidance (ISG) is documented for use by the NRC staff, industry, and other interested stakeholders until it is incorporated into the license renewal guidance documents such as the SRP-LR and the GALL Report.

The following table provides the current set of ISGs issued by the staff, as well as the SER sections in which the staff addresses ISG issues.

ISG Issue (Approved ISG No.)	**Purpose**	**SER Section**
GALL Report presents one acceptable way to manage aging effects **(ISG-1)**	This ISG clarifies that the GALL Report contains one acceptable way, but not the only way, to manage aging for license renewal.	N/A
SBO Scoping **(ISG-2)**	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.	2.5.1 3.6.2.3
Concrete AMP **(ISG-3)**	Lessons learned from the GALL demonstration project indicated that GALL is not clear on whether concrete requires an AMP.	3.5.2.2

ISG Issue (Approved ISG No.)	**Purpose**	**SER Section**
FP System Piping **(ISG-4)**	This ISG clarifies the staff position for wall-thinning of the FP piping system in GALL AMPs XI.M26 and XI.M27. The staff's new position is that there is no need to disassemble FP piping, as disassembly can introduce oxygen to FP piping, which can accelerate corrosion. Instead, use a non-intrusive method, such as volumetric inspection. Testing of sprinkler heads should be performed at year 50 of sprinkler system service life, and every 10 years thereafter. This ISG eliminates the Halon/carbon dioxide system inspections for charging pressure, valve line-ups, and the automatic mode of operation test from GALL; the staff considers these test verifications to be operational activities.	2.3.3.15 3.0.3.2.7

ISG Issue (Approved ISG No.)	**Purpose**	**SER Section**
Identification and Treatment of Electrical Fuse Holders **(ISG-5)**	This ISG includes electrical fuse holders 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
The ISG Process **(ISG-8)**	This ISG provides clarification and update to the ISG process on Improved License Renewal Guidance Documents.	N/A
Standardized Format for License Renewal Applications **(ISG-10)**	The purpose of this ISG is to provide a standardized license renewal application format for applicants.	N/A

1.5 Summary of Open Items

An open item (OI) is an issue that, in the staff's judgment, has not been resolved in a manner that meets all applicable regulatory requirements. After completing a review of the LRA for

Units 1 and 2, including all additional information and clarifications submitted to the staff as of Septmeber 29, 2005, the staff has identified no OIs.

1.6 Summary of Confirmatory Items

A confirmatory item (CI) is an issue that the applicant and the staff have resolved, but for which the applicant has not yet formally submitted the resolution. After completing a review of the LRA for Units 1 and 2, including all additional information and clarifications submitted to the staff as of Septmeber 29, 2005, the staff has identified no CIs.

1.7 Summary of Proposed License Conditions

As a result of the staff's review of the LRA for Units 1 and 2, including subsequent information and clarifications provided by the applicant, the staff identified three proposed license conditions.

The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed licenses.

The second license condition requires that the activities identified in SER Appendix A be completed in accordance with the schedule in Appendix A.

The third license condition requires that all capsules in the reactor vessel that are removed and tested must meet the requirements of ASTM E 185-82 to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the staff, as required by 10 CFR Part 50, Appendix H.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 <u>Scoping and Screening Methodology</u>

2.1.1 Introduction

Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Section 54.21, "Contents of Application — Technical Information," requires that each application for license renewal contain an integrated plant assessment (IPA). Furthermore, the IPA must identify those structure and components (SCs) that are subject to an aging management review (AMR) from the system, structure, and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4(a).

In License Renewal Application (LRA) Section 2.1, "Scoping and Screening Methodology," the applicant described the scoping and screening methodology used to identify SSCs at Brunswick Steam Electric Plant (BSEP) within the scope of license renewal and SCs that are subject to an AMR. The staff reviewed the applicant's scoping and screening methodology to determine whether it meets the scoping requirements stated in 10 CFR 54.4(a) and the screening requirements stated in 10 CFR 54.21.

In developing the scoping and screening methodology for the BSEP LRA, the applicant considered the requirements of the Rule, the statements of consideration (SOCs) for the Rule, and the guidance presented by NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, March 2001. In addition, the applicant also considered the staff's correspondence with other applicants and with NEI in the development of this methodology.

2.1.2 Summary of Technical Information in the Application

In LRA Sections 2.0 and 3.0, the applicant provided the technical information required by 10 CFR 54.21(a). In LRA Section 2.1, "Scoping and Screening Methodology," the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a), as well as the process used to identify the SCs that are subject to an AMR as required by 10 CFR 54.21(a)(1).

Additionally, LRA Section 2.2, "Plant Level Scoping Results;" Section 2.3, "Scoping and Screening Results - Mechanical Systems;" Section 2.4, "Scoping and Screening Results - Structures;" and Section 2.5, "Scoping and Screening Results - Electrical and Instrumentation and Control (I&C) Systems;" amplify the process that the applicant used to identify the SCs that are subject to an AMR. LRA Section 3, "Aging Management Review Results," contains the following information:

- Section 3.1, “Aging Management of Reactor Vessel, Internals and Coolant Systems”
- Section 3.2, “Aging Management of Engineered Safety Features Systems”
- Section 3.3, “Aging Management of Auxiliary Systems;” Section 3.4, “Aging Management of Steam and Power Conversion Systems”
- Section 3.5, “Aging Management of Containment, Structures, and Component Supports”
- Section 3.6, “Aging Management of Electrical and Instrumentation and Controls”

LRA Section 4, “Time-Limited Aging Analyses,” contains the applicant’s identification and evaluation of TLAAs.

2.1.2.1 Scoping Methodology

2.1.2.1.1 Application of the Scoping Criteria in 10 CFR 54.4(a)

Application of the Scoping Criteria in 10 CFR 54.4(a)(1). In LRA Sections 2.1, “Scoping and Screening Methodology,” 2.1.1, “Scoping,” and 2.1.1.1, “Safety-related Criteria Pursuant to 10 CFR 54.4(a)(1),” the applicant discussed the scoping methodology as it related to safety-related (SR) criteria in accordance with 10 CFR 54.4(a)(1).

The LRA states that 10 CFR 54.4(a)(1) pertains to SR SSCs and further states that SSCs within the scope of license renewal include SR SSCs that must remain functional during and following design-basis events (DBEs), as defined in 10 CFR 50.49(b)(1), to ensure the following functions:

(8) The integrity of the reactor coolant pressure boundary (RCPB)

(9) The capability to shut down the reactor and maintain it in a safe shutdown condition

(10) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11 of this chapter, as applicable

LRA Section 2.1.1.1 states that the PassPort equipment database (EDB) was used to implement the graded quality classification system defined at BSEP. The EDB applied the Quality Class A classification to structures and components necessary, actively or passively, to assure the accomplishment of SR functions. Component quality classifications documented in the EDB are derived according to plant administrative controls using functions defined in CLB documents, including the UFSAR.

A comparison of the criteria of 10 CFR 54.4(a)(1) with the definition of the EDB Quality Class A classification indicates that the Quality Class A criteria are consistent with 10 CFR 54.4(a)(1) with the exception of the references to 10 CFR 50.34(a)(1), which is associated with applications for an initial operating license and is not applicable to BSEP; and 10 CFR 50.67(b)(2), which is associated with accident source term limits and is discussed below. The LRA indicates that at BSEP, 10 CFR Part 100 guidelines have been applicable, historically, under the CLB; 10 CFR 100.11 has been used to identify components credited with preventing and mitigating offsite exposures. Concerning 10 CFR 50.67(b)(2), the LRA states that the staff issued a safety evaluation authorizing the use of alternative source terms (ASTs) under 10 CFR 50.67(b)(2) in support of the ongoing BSEP Extended Power Uprate Project. Consistent with the terms of the AST license amendment, license renewal scoping impacts arising from the use of nonsafety-related (NSR) equipment to support the use of an AST are evaluated in accordance with the criteria of 10 CFR 54.4(a)(2).

The LRA states that EDB Quality Class A classification is consistent with the scoping criteria of 10 CFR 54.4(a)(1), such that this designation is sufficient to facilitate scoping of SSCs in accordance with 10 CFR 54.4(a)(1). For the purposes of license renewal, any system, including support systems, or structure that contains one or more SR component is considered to be an SR system or structure.

Application of the Scoping Criteria in 10 CFR 54.4(a)(2). LRA Section 2.1.1.2 states that since BSEP implemented a graded quality classification system in the mid-1980s, it has made extensive use of augmented quality classifications to identify SSCs that have functional or physical interactions with SR equipment. These augmented quality classifications have been assigned to NSR components and documented in the EDB. The EDB quality classification designations have been reconciled with license renewal scoping criteria to provide a means for scoping of license renewal components and associated systems/structures. The EDB quality classifications were used to identify NSR components that can be a potential source of damage to nearby SR components. In addition to scoping on the basis of augmented quality designations, an extensive review was performed to identify additional candidates for inclusion based on the CLB, a review of site and industry operating experience, and other pertinent sources of information.

The LRA states that the following NSR SSCs were not considered subject to the review: SSC hypothetical failures that are not part of the plant CLB, or that have not been experienced previously; SCs that would have been included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) that were already included in accordance with 10 CFR 54.4(a)(3); NSR equipment used to establish initial conditions for equipment operation; and NSR equipment that actuates SR equipment that does not result in the loss of an SR function.

BSEP design and licensing basis information was reviewed to identify NSR SSCs that function to directly support or that could interact with an SR system or structure and whose failure or interaction could prevent the performance of a required intended function. Sources of this information include design-basis documents (DBDs), the UFSAR, plant drawings, and other CLB documentation, as well as the EDB and the Maintenance Rule database. The specific function/interaction required of an NSR SSC was also identified for each instance in which NSR SSCs were credited in the CLB. SSCs identified in this category were designated as being within the scope of license renewal per the 10 CFR 54.4(a)(2) criteria, and the associated function or interaction was considered a system/structure intended function.

The LRA states that the majority of NSR piping connected to SR piping can be identified by EDB quality class designation. Where necessary, plant design documents were reviewed or conservative assumptions made to identify additional piping/components in this category. Systems having components credited in this regard were included within the scope of license renewal. The CLB position for seismically induced effects between connected NSR and SR piping was provided in response to an NRC comment documented in Amendment 15 of the

BSEP UFSAR, dated March 1973. The position stated that, in cases where SR piping and NSR piping are connected, the analysis of seismically induced effects was continued well into the NSR piping in order to include the effects that NSR piping has on the adjoining SR piping. Generally, this continuation was to a point where the NSR pipe was restrained in three directions. If this was not practical, the NSR pipe was analyzed up to a point in the system where it was supported in three directions by three individual supports.

Interactions between SR SSCs and non-connected NSR SSCs were defined as NSR SSCs having physical interaction with SR SSCs that impairs an SR SSC's function and is associated with NSR SSC piping degradation and loss of pressure boundary. The LRA indicates that the UFSAR Section 3.6.1 states "operating experience has shown that mechanisms do not exist which could cause the instantaneous failure of piping systems without prior detectable leakage." The LRA indicates that the scoping process was based on the concept that the piping in operating systems that has retained its functional integrity will remain supported so long as its supports do not fail and that direct physical interaction with SR SSCs is prevented by the function of piping supports; therefore, the preventive option consists of managing the aging effects of the supports. Aging effect evaluations associated with direct physical interactions between NSR and SR components are limited to piping/component supports. Civil/structural scoping has included the supports for NSR piping/components that have the capability of preventing satisfactory accomplishment of any required SR functions in spaces where SR equipment within the scope of license renewal is present.

The LRA states that indirect physical interactions between spatially related NSR and SR piping/components are not limited to seismic events, but may include other age-related failures of NSR SSCs. The scoping process for these indirect interactions was accomplished on the basis of a systematic review of areas and hazards. Plant drawings and documentation were reviewed to identify areas housing SR SSCs. Pressure-retaining component types were identified, since potential spatial interactions (flooding, spray, wetting) were assumed to be related to liquid-filled piping systems. Pressure-retaining NSR components located in structures housing SR SSCs were identified on the basis of EDB location information, plant drawings, and other pertinent data. This group of components was further refined to exclude specific components evaluated as not presenting a spatial interaction hazard. Systems having NSR components identified as having the potential for adverse spatial interaction with SR SSCs were included within the scope of license renewal.

Additional scoping evaluations were performed to make scoping determinations against 10 CFR 54.4(a)(2) that cannot be made on the basis of EDB classification. Notable scoping additions include selected NSR connected piping, valves, and components (seismic support), NSR piping and supports in the proximity of SR SSCs (seismic interaction), service water discharge piping (flow path), long-term nitrogen supply to main steam safety relief valves (flow path), reactor building air receivers (explosion/missile hazard), and reactor building leak detection equipment and floor drain systems (flood hazard).

BSEP has implemented the use of accident source term (AST) for evaluation of accident consequences in accordance with 10 CFR 50.67. This activity, undertaken in support of the BSEP Extended Power Uprate (EPU) project, makes use of an NRC-approved methodology for evaluation of an NSR alternate leakage treatment path from the main steam line isolation valves (MSIVs) to the main condenser. Since the BSEP license amendment credits the use of

NSR SSCs in AST analyses, these have been included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

Application of the Scoping Criteria in 10 CFR 54.4(a)(3). In LRA Sections 2.1, “Scoping and Screening Methodology;” 2.1.1, “Scoping;” and Section 2.1.1.3, “Other Scoping Pursuant to 10 CFR 54.4(a)(3),” the applicant discussed the scoping methodology as it related to the regulated event criteria in accordance with 10 CFR 54.4(a)(3).

The LRA states that 10 CFR 54.4(a)(3) indicates that SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC’s regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), PTS (10 CFR 50.61), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) are within the scope of license renewal.

With the exception of pressurized thermal shock, which is not applicable to BWRs, current licensing basis evaluations have been performed to identify and document those SSCs credited for compliance of each of these regulations. For these SSCs, the system/structure-level intended function is that function which is relied upon in safety analyses or evaluations to demonstrate compliance with NRC requirements for the regulated event. Systems or structures that have one or more components credited for demonstrating compliance with one of the regulated events are within the scope of license renewal per the 10 CFR 54.4(a)(3) criteria.

2.1.2.1.2 Documentation Sources Used for Scoping and Screening

In LRA Sections 2.1.1.1, 2.1.1.2, and 2.1.1.3, the applicant stated information derived from the CLB information, design and licensing basis information, design basis documents (DBDs), the UFSAR, plant drawings, Maintenance Rule database, and the equipment database (EDB) was reviewed during the license renewal scoping and screening process. The applicant used this information to identify the functions performed by plant systems, structures, and components. These functions were then compared to the scoping criteria in 10 CFR 54.4(a)(1)-(3) to determine if the associated plant system, structure, or component performed a license renewal intended function and to develop the list of SCs subject to an AMR.

2.1.2.2 Screening Methodology

2.1.2.2.1 Mechanical Screening

The LRA states that following scoping for mechanical systems, the applicant performed screening to identify those mechanical components that were subject to an AMR. The applicant stated in LRA Section 2.1.2.1, “Mechanical Components,” that the following methodology was used:

- System intended function boundaries were established, and mechanical components subject to screening were identified. Additionally, license renewal boundary drawings were developed for selected BSEP systems within the scope of license renewal. These boundary drawings were used during the screening process for purposes such as identification of untagged commodities within evaluation boundaries.
- Mechanical components were subjected to screening based on active/passive function. THE BSEP EDB equipment codes were used to sort many components in accordance

to engineering discipline, active/passive determination and recommended intended function. Components having equipment types designated as active were not subject to AMR and were categorically screened out on this basis. Components having equipment types that are indeterminate were reviewed individually to ascertain if they are active and thereby excluded from AMR requirements.

- Mechanical components were reviewed to determine if they constituted a complex assembly. Complex assemblies were considered active and could be excluded from the scope of license renewal. However complex assemblies which include piping or components that interface with external equipment, or components that cannot be adequately tested/monitored as part of the complex assembly, were subject to screening.
- Mechanical components were reviewed to determine if they were subject to periodic replacement. Those mechanical component types subject to replacement based on a qualified life or specified time period (i.e., are not long-lived components) were screened as not subject to AMR.
- Consumable items were evaluated. Consumable parts of a component may be passive, long-lived, and necessary to fulfill an intended function. Screening of consumables was either done as part of the component AMR or the item was excluded based on NRC screening guidance.
- Component intended functions were identified. Each component subject to an AMR was evaluated to determine if the component-level mechanical function(s) were performed without moving parts or change in configuration, in fulfilling or supporting system intended functions.

Components determined to be not subject to an AMR were screened out. These include components that are (a) active, (b) short-lived or replaced based on qualified life or specific time period, or (c) not credited with performance of a mechanical intended function.

2.1.2.2.2 Structural Screening

LRA Section 2.1.2.2 states that the screening process was performed on each structure identified to be within the scope of license renewal. This method evaluated the individual SCs included on or within structures, within the scope of license renewal, to identify specific SCs or SC groups that require an AMR. **The LRA describes the following sequence of steps performed for each structure which had been determined to be within the scope of license renewal**:

(2) Typical components were grouped together and screened as a single commodity. The source of the civil commodities list was a combination of those civil components identified by tag number in the EDB and those un-tagged civil components identified through industry experience and a review of the plant CLB. An active/passive determination was performed based on whether the commodity supports its intended function without moving parts or without a change in configuration or properties. A determination of commodity replacement based on a qualified life or specified time period was performed for each commodity type. Finally, a set of potential intended functions was developed for each commodity group.

(3) Civil screening was performed on a structural system basis and only civil commodities located within the specific structural system being screened were addressed. The identification of civil commodities for a specific structure was performed using EDB location data, design drawings, general arrangement drawings, penetration drawings, plant modifications, the UFSAR, DBDs, system descriptions, and plant walkdowns. EDB equipment types within a specific structure were reviewed and civil commodities were assigned to the structure based on that review.

Evaluation boundaries between mechanical components, electrical components, and structures and structural components were coordinated between the discipline reviewers. This same methodology was used with components identified by means other than EDB, such as an UFSAR discussion of a specific component or design feature, an untagged component identified on a plant drawing, or a component observed during a plant walkdown.

(4) The commodity-specific intended functions were developed based on comparison of the potential intended functions from the generic commodity groups to the specific intended functions of the structure and the EDB component quality classification. The screening process reviewed EDB equipment types, design drawings, general arrangement drawings, plant modifications, the UFSAR, DBDs, system descriptions, and plant walkdown results within each structure and developed a list of commodities within that structure requiring aging management review. Those SCs that have a component or commodity intended function that supports a structure intended function were subject to an AMR.

2.1.2.2.3 Electrical/I&C Screening

LRA Section 2.1.2.3 described the methodology used to identify electrical and instrumentation and control (I&C) components that are subject to an AMR. For electrical and I&C SCs, the applicant used the component commodity group approach consistent with the guidance in NEI 95-10.

The sequence of steps that the applicant used to identify electrical and I&C SCs that require an AMR included:

(5) The EDB was used to identify electrical equipment and components types within systems and structures determined to be within the scope of license renewal.

(6) The UFSAR, plant drawings, and other documents, were used to identify electrical equipment and component types within electrical and I&C systems determined to be within the scope of license renewal in addition to those identified in the EDB.

(7) The component types associated with electrical and I&C components within scope of license renewal were organized into commodity groups such as circuits, breakers, cables and sensors. In general, grouping of component types followed the guidance in NEI 95-10 to group components based on similar functions.

(8) The electrical and I&C component commodity groups that perform an intended function without moving parts or without a change in configuration (passive) were identified.

(9) Passive electrical and I&C commodity groups, component commodity groups that are not subject to replacement based on a qualified life or time period, were identified.

Electrical and I&C components that were screened in accordance with the steps above and meet the requirements of 10 CFR 54.21(a)(1)(i) were determined to be subject to an AMR.

2.1.3 Staff Evaluation

As part of the review of the applicant's LRA, the staff evaluated the scoping and screening activities described in the following sections of the application:

- Section 2.1, "Scoping and Screening Methodology," to verify that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), a(2), and a(3).
- Section 2.2, "Plant Level Scoping Results;" Section 2.3, "Scoping and Screening Results - Mechanical Systems;" Section 2.4, "Scoping and Screening Results - Structures;" and Section 2.5, "Screening Results - Electrical and Instrumentation and Controls (I&C) Systems" to verify that the applicant described a process for determining structural, mechanical, and electrical components at BSEP that are subject to an AMR for renewal in accordance with the requirements of 10 CFR 54.21(a)(1) and (2).

In addition, the staff conducted a scoping and screening methodology audit at BSEP March 1 through 4, 2005. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the application and the requirements of the Rule. The staff reviewed implementation procedures and engineering reports which describe the scoping and screening methodology implemented by the applicant. In addition, it conducted detailed discussions with the cognizant engineers on the implementation and control of the program, and reviewed administrative control documentation and selected design documentation used by the applicant during the scoping and screening process. It further reviewed a sample of system scoping and screening results reports for main feedwater to ensure the methodology outlined in the administrative controls was appropriately implemented, and the results reports were found to be consistent with the CLB as described in the supporting design documentation.

2.1.3.1 Scoping Methodology

The staff reviewed implementation procedures and engineering reports which describe the scoping and screening methodology implemented by the applicant. These procedures included: EGR-NGGC-0501, "Nuclear Plant License Renewal Program;" EGR-NGGC-0502, "System/Structure Scoping for License Renewal;" EGR-NGCC-0503, "Mechanical Component Screening for License Renewal;" EGR-NGCC-0505, "Electrical Component Screening and Aging Management Review for License Renewal;" EGR-NGGC-0506, "Civil/Structural Screening and Aging Management for License Renewal;" OENP-33.5, "Quality Classification Analysis of Structures, Systems, and Components;" and BNP-LR-002, "Bulk Screening of EDB Equipment Types for License Renewal." The staff found that the scoping and screening methodology instructions were consistent with LRA Section 2.1 and were of sufficient detail to provide the applicant's staff with concise guidance on the scoping and screening implementation process to be followed during the LRA activities. In addition to the implementing procedures, the staff reviewed supplemental design information including design-basis drawings, system drawings, and selected licensing documentation relied upon by the applicant during the scoping and screening phases of the review. The staff found these design documentation sources to be useful for ensuring that the initial scope of SSCs identified by the applicant was consistent with the CLB of the BSEP.

2.1.3.1.1 Application of the Scoping Criteria in 10 CFR 54.4(a)

Application of the Scoping Criteria in 10 CFR 54.4(a)(1)

10 CFR 54.4(a)(1) requires, in part, that the applicant consider all SR SSCs that are relied upon to remain functional during and following DBEs to ensure the following functions: (1) the integrity of the reactor coolant pressure boundary, (2) the ability to shut down the reactor and maintain it in a safe shutdown condition, or (3) the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11 to be within the scope of the license renewal.

The applicant used the EDB as the primary source of information to determine whether an SC would be considered within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1). The SCs' quality designations were determined in accordance with BSEP procedure OENP-33.5, "Quality Classification Analysis of Structures, Systems, and Components," and documented in the EDB which had been developed and maintained in accordance with quality assurance requirements of 10 CFR Part 50, Appendix B. SR SCs were identified in the EDB as meeting one of approximately seventeen Quality Class A designations. The Quality Class A designation identified the operational attributes and safety functions of the SCs. All SCs designated as Quality Class A were determined to be within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1).

The staff determined that the applicant had performed component-based scoping and had included SCs within the scope of license renewal based upon the SC's classification within the EDB relative to the criteria of 10 CFR 54.4 (a)(1), (a)(2), or (a)(3). The applicant had then included all systems within the scope of license renewal which contained any SCs which had been determined to be within the scope of license renewal based on the SC's classification within the EDB. The applicant indicated that the system CLB documentation, including the system intended functions, had been reviewed to verify that all SCs within the scope of license renewal had been identified.

In RAI 2.1-1, dated April 8, 2005, the staff stated that it reviewed the information contained in the LRA, discussed the process with the applicant, and reviewed the applicable process implementation guidance. The staff determined that the process by which the CLB information, including system intended functions, had been reviewed and considered during the scoping process was not clearly documented in the LRA.Therefore, the staff requested that the applicant document how the CLB information, including system intended functions, was considered during the scoping process.

In its response, by letter dated May 4, 2005, the applicant stated that the EDB had been developed from the Q-List, which is maintained in accordance with requirements of 10 CFR Part 50, Appendix B, to create a more detailed, component-level quality classification system for plant equipment. The procedure for classification of components in EDB utilizes a process that begins with the established intended functions performed by the parent system or structure.

During the license renewal review, information from the EDB was evaluated to determine its suitability for use in the scoping process and a license renewal calculation was developed to document the evaluation. The review determined that EDB quality classifications could be used to facilitate identification of SSCs within the scope of license renewal and provide an indication of the intended functions that the SSCs perform. The methodology through which SCs are assigned a quality classification within the EDB also involves a procedurally controlled process that considers the intended functions of the parent SSC as documented in CLB documents.

The scoping process checked EDB component results against other sources and the EDB function descriptions were compared with UFSAR and DBD function descriptions. In addition, component-level scoping results were mapped to system drawings. Component mapping on the drawings afforded an effective check to ensure that the functions described in the CLB documents were consistent with EDB information.

In addition to the inclusion of SSCs based on quality classifications of individual SCs in the EDB, the scoping process included a review of plant and CLB documents to the extent required to develop the descriptive material, including system intended functions, for use in the LRA. The documents reviewed included the UFSAR, DBDs, system descriptions, docketed correspondence, the EDB, and the Maintenance Rule database. The review was performed to document the SSC descriptions and functions to be incorporated into the SSC scoping worksheets and ultimately into LRA Sections 2.3 and 2.4, so that the description of each SSC and its functions were available for review.

The staff reviewed the additional information provided by the applicant and determined the component-level classification contained in the EDB was based on the parent system intended functions. In addition, the applicant had also considered the system intended functions during the review of information including the CLB, UFSAR, DBDs system descriptions. Therefore, the staff's concern described in RAI 2.1-1 is resolved.

<u>Conclusion</u>. As part of the review of the applicant's scoping methodology, the staff reviewed a sample of the license renewal database 10 CFR 54.4(a)(1) scoping results, reviewed a sample of the analyses and documentation to support these reviews, and discussed the methodology and results with the applicant's personnel responsible for these evaluations. The staff verified that the applicant had identified and used pertinent engineering and licensing information in order to determine the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) criteria. On the basis of this sample review and discussions with the applicant, the staff determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(1) was adequate.

<u>Application of the Scoping Criteria in 10 CFR 54.4(a)(2)</u>. Pursuant to 10 CFR 54.4(a)(2), the applicant must consider all NSR SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4(a)(1)(i) - (iii), to be within the scope of the license renewal. By letters dated December 3, 2001, and March 15, 2002, the staff issued its position to NEI, providing staff expectations for determining which SSCs meet the 10 CFR 54.4(a)(2) criterion.

The December 3, 2003, letter (ADAMS accession ML033370195) provided specific examples of operating experience which identified pipe failure events (summarized in NRC Information Notice (IN) 2001-09, “Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor”) and the approaches the NRC considers acceptable to determine which piping systems should be included within the scope of license renewal based on the 10 CFR 54.4(a)(2) criterion. The March 15, 2002, letter (ADAMS accession ML020770026) further described the staff’s expectations for the evaluation of non-piping SSCs to determine which additional NSR SSCs are within the scope of license renewal. The position states that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant’s CLB, engineering judgement and analyses, and relevant operating experience. The paper further describes operating experience as all documented plant-specific and industry-wide experience which can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports, and engineering evaluations.

In keeping with the NEI draft position on NSR SSCs that could adversely affect SR SSCs, the applicant developed guidance for interpreting and applying the 10 CFR 54.4(a)(2) criteria including NSR components spatially oriented near SR components, seismic II/I components, NSR piping attached to SR piping, flooding, missiles, and high energy line breaks. The applicant used the EDB quality classifications to identify NSR components that could be considered a potential source of damage to nearby SR components.

The applicant’s guidance for performing 10 CFR 54.4(a)(2) scoping of NSR SSCs was documented in the following Brunswick Nuclear Plant (BNP) calculations: Nuclear Generation Group calculations BNP -LR-003, “Use of Equipment Database for License Renewal Scoping Calculations;” BNP-LR-007, “License Renewal Scoping Calculation for Criteria 10 CFR 54.4(a)(2);” BNP-LR-009, “Civil Nonsafety-Related (II/I) Determination for License Renewal;” BNP-LR-012, “License Renewal Scoping for Seismic Continuity Piping;” and BNP-LR-013, “License Renewal Scoping Calculation for Nonsafety-Related Spatial Interaction Piping.” The applicant reviewed the plant’s design and licensing basis information to identify NSR SSC interactions with SR SSCs that could prevent the performance of a required intended function. For each such instance, the specific interaction that may affect the function of SR SSCs was identified. The SSCs meeting these criteria were designated as within the scope of the 10 CFR 54.4(a)(2) criteria.

LRA Section 2.1.1.2, “Non-Safety Related Criteria Pursuant to 10 CFR 54.4(a)(2),” discusses the methodology for including NSR SSCs within the scope of license renewal whose failure could prevent the satisfactory accomplishment of any of the functions identified for SR SSCs interim staff guidance (ISG)-9. Sources of information reviewed by the applicant included DBDs, the UFSAR, EDB, Maintenance Rule database, and docketed correspondence. The specific function/interaction required of an NSR SSC was also identified for each instance where NSR SSCs were credited in the CLB. SSCs identified in this category were designated as within the scope of license renewal pursuant to 10 CFR 54.4(a)(2).

The applicant prepared calculations which addressed the issue of including within the scope of license renewal the NSR piping attached to SR piping that is seismically designed and supported up to the “first seismic anchor” past the SR/NSR interface. The LRA states that the analysis of seismically induced effects was continued well into the NSR piping in order to include the effects on the adjoining SR piping. Generally, this continuation was to a point where the Category II piping was restrained in three directions or if not practical, the Category II piping was analyzed up to a point in the system where it was supported in three directions by three individual supports. The applicant stated this position is consistent with the plant's CLB for seismically induced effects between connected NSR and SR piping, as documented in Comment C.54 of the UFSAR, Amendment 15, dated March 1973. The comment responds to an earlier Atomic Energy Commission question requesting that the applicant describe the evaluation performed to determine seismically induced effects of Category II piping systems on Category I piping. BNP was designed and built prior to issuance of RG 1.29 which required NSR components with the potential to impact safety components to be seismically supported.

During the audit, the team reviewed a study report prepared for CP&L in 1986 by United Engineers and Constructors, the architect-engineer for the plant, entitled "Documentation of Seismic Class I Boundary Conditions." The purpose of the report was to document the seismic Class I boundaries, identify supports utilized to define the seismic stress analysis boundary, and ensure that each boundary had been adequately addressed and evaluated.

In RAI 2.1-2, dated April 8, 2005, the staff stated that based on a review of the LRA, the applicant's scoping and screening implementation procedures, calculations, and discussions with the applicant, the staff determined that additional information was required with respect to certain aspects of the applicant's evaluation pursuant to 10 CFR 54.4(a)(2). Therefore, the staff requested confirmation that use of the term "first seismic anchor" is, in fact, consistent with the CLB position for seismically induced effects between connected NSR and SR piping. The staff also requested that the applicant further describe the methodology of its LRA in relation to the CLB.

In its response, by letter dated May 4, 2005, the applicant stated that during the original final safety analysis report (FSAR) development, the applicant had documented the effects of seismic Category II piping systems on seismic Category I piping systems. In cases where Category I piping and Category II piping are connected, the analysis was continued well into the Category II piping in order to include the effects that Category II piping has on the adjoining Category I piping. Generally, this continuation was to a point where the Category II pipe was restrained in three directions. If this was not practical, the Category II pipe was analyzed up to a point in the system where it was supported in three directions by three individual supports. In addition, the BSEP architect/engineer later provided study reports to document pipe stress analysis methodology. One of these study reports specifically addressed seismic Class I boundary conditions. Corporate procedures for the performance of pipe stress analysis have incorporated the aforementioned study report by reference. This information was incorporated into the design control documents and ensures that the CLB requirements are met.

The applicant further stated that the methodology employed to validate that all seismically connected piping per ISG-09 was properly evaluated for inclusion within the scope of license renewal was multi-faceted. BSEP employed a spaces approach for the review of liquid-filled piping systems. Liquid-filled piping located in buildings housing SR components was brought within the scope of license renewal unless a specific documented evaluation was performed to exclude a particular space. When this evaluation was complete, a separate evaluation was performed to ensure that the seismically connected piping (associated with SR/NSR boundaries), that had not yet been included, was brought within the scope of license renewal consistent with the CLB. The license renewal boundary drawings were reviewed to ensure that there were no anomalous conditions that required further evaluation.

The staff reviewed the applicant's response and determined that the applicant had previously evaluated the NSR/SR piping interfaces and that the results of the previous evaluations were conservative and consistent with the plant's design basis, the UFSAR, and the CLB. Therefore, the staff's concern described in RAI 2.1-2 is resolved.

Conclusion. Based on the information supplied by the applicant, including determination of credible failures that could impact the ability of SR SSCs to perform their intended functions, evaluation of relevant operating experience, and incorporation of identified NSR SSCs into the applicant's AMPs; and the results of NRC inspection and audit activities, the staff concluded that the applicant has supplied sufficient information to demonstrate that all SSCs that meet the 10 CFR 54.4(a)(2) scoping requirements have been identified as being within the scope of license renewal.

Application of the Scoping Criteria in 10 CFR 54.4(a)(3). 10 CFR 54.4(a)(3) requires, in part, that the applicant consider all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), PTS (10 CFR 50.61), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) to be within the scope of the license renewal.

In LRA Sections 2.1.1.3, "Other Scoping Pursuant to 10 CFR 54.4(a)(3),"and 2.1.4, "Interim Staff Guidance Issues," the applicant discussed the methodology used to identify SSCs credited for performing a function that demonstrates compliance with regulations for fire protection, EQ, ATWS, and SBO pursuant to the 10 CFR 54.4(a)(3) license renewal scoping criteria. The applicant did not evaluate PTS because it is not applicable to BWRs. The applicant's approaches for scoping systems and structures required mitigating each of these four regulated events, as described in the following sections.

> Fire Protection - The applicant described the scoping of SSCs required to demonstrate compliance with the fire protection requirements of 10 CFR 50.48 in LRA Section 2.1.1.3.1, "Fire Protection." The applicant stated that a detailed review of the CLB, which included the EDB, the Safe Shutdown Analysis Report, the fire protection safe shutdown and SBO screening procedure, and the Fire Protection Program Manual, for fire protection was performed and SSCs that support either fire protection design features or safe shutdown following a postulated fire are within the scope of license renewal, and the associated intended functions relied were identified.
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> Environmental Qualification - The applicant described the scoping of SSCs required to demonstrate compliance with EQ requirements of 10 CFR 50.49 in LRA Section 2.1.1.3.2, "Environmental Qualification." Electric equipment important to safety that is required to be environmentally qualified to mitigate certain accidents that would result in harsh environmental conditions in the plant is defined in 10 CFR 50.49. The applicant stated that an EQ Master List (EQML) was developed in accordance with the requirements of 10 CFR 50.49(b) based on 1) a review of the BSEP design-basis accidents, 2) the resulting environmental service conditions, 3) the functional requirements of the systems, 4) the functional requirements of individual components required to isolate the break or mitigate or monitor the effects of the accident, and 5) the physical location of the components. THE EQML is maintained in the EDB, which was used as the principal input document for scoping of SSCs. Any system that contained

one or more components designated as EQ-related in the EDB was considered within the scope of license renewal per 10 CFR 54.4(a)(3).

Anticipated Transients without Scram (ATWS) - The applicant described the scoping of SSCs required to demonstrate compliance with the ATWS requirements of 10 CFR 50.62 in LRA Section 2.1.1.3.3, “Anticipated Transients without Scram.” The applicant stated that the BSEP design features related to ATWS are within the scope of license renewal because they are relied on to meet the requirements of 10 CFR 50.62. The applicant stated that ATWS mitigation is accomplished by the use of three systems at BSEP: 1) the alternate rod injection system, 2) the standby liquid control (SLC) system, and 3) the ATWS-recirculation pump trip system. Based on a review of the CLB, the intended functions supporting the 10 CFR 50.62 requirements were determined.

Station Blackout - In an April 1, 2002 letter from D. Matthews to A. Nelson and D. Lochbaum, the staff provided guidance on the scoping of equipment relied on to meet the requirements of 10 CFR 50.63. In this letter, the staff noted that, consistent with the requirements specified in 10 CFR 54.4(a)(3) and 10 CFR 50.63(a)(1), the plant system portion of the offsite power system used to connect the plant to the offsite power source should be included within the scope of the rule. The applicant described the scoping of SSCs required to demonstrate compliance with the SBO requirements of 10 CFR 50.63 in LRA Section 2.1.1.3.4, “Station Blackout.” The applicant noted that the EDB quality classifications that have been assigned to components credited with compliance with SBO requirements were used to identify the applicable equipment. In addition, the applicant augmented the EDB by identifying components with additional reviews of the Station Blackout Coping Analysis Report and other plant documents and procedures. The applicant stated that, based on the review of the CLB for SBO, the equipment performing intended functions required for compliance with 10 CFR 50.63 was determined and was included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3). The staff determined that the applicant’s approach to scoping SSCs relied on to demonstrate compliance with 10 CFR 50.63 was consistent with the staff’s April 1, 2002, interim guidance (ISG-2).

Conclusion. As part of the review of the applicant’s scoping methodology, the staff reviewed a sample of the license renewal database 10 CFR 54.4(a)(3) scoping results, reviewed a sample of the analyses and documentation to support these reviews, and discussed the methodology and results with the applicant’s personnel responsible for these evaluations. The staff verified that the applicant had identified and used pertinent engineering and licensing information in order to determine the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) criteria. Based on this sampling review and discussions with the applicant, the staff determined that the applicant’s methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54.4(a)(3) was adequate.

2.1.3.1.2 Mechanical Component Scoping

The applicant described the methodology used for mechanical scoping in LRA Section 2.1.1 “Scoping;” EGR-NGGC-0502, “System/Structure Scoping for License Renewal;” and BNP-License Renewal (LR)-002, “Bulk Screening of EDB Equipment Types for License Renewal.” The applicant developed a list of SSCs using the information contained in the EDB.

The EDB and the CLB were reviewed to identify SSCs credited with compliance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The primary source of this information was the component-level classification provided in the EDB. The system and component intended functions had been used in determinating the quality classification of SCs within the EDB. Systems which contained components determined to meet the requirements of 10 CFR 54.4(a)(1), (a)(2), and (a)(3) were considered within the scope of license renewal.

The applicant noted that while the quality classification used in the EDB would accurately identify the SCs that would meet the requirements of 10 CFR 54.4(a)(1) and a portion of those SCs that would meet the requirements of 10 CFR 54.4(a)(2), there may be NSR SCs which would have potential physical interactions with SR SSCs that might not be identified in the EDB. In this case, the applicant performed additional CLB reviews and did on-site walkdowns to identify NSR SSCs that could potentially interact with SR SSCs and included the identified NSR SSCs within the scope of license renewal. In addition, the applicant indicated that additional reviews of the CLB were performed to identify all SCs required to meet those system functions credited with compliance with regulated events (10 CFR 54.4(a)(3)) and to include the identified SCs within the scope of license renewal.

For each mechanical system the applicant developed a scoping worksheet in accordance with calculation BNP-LR-010, “License Renewal Project Scoping Calculation.” These worksheets provided a general description of the mechanical system, identified whether the system was in or out of the scope of license renewal, identified a list of applicable CLB documents, and identified each of the system functions required to support the component functions meeting license renewal scoping criteria.

The staff reviewed the scoping process for a selected mechanical system, the main steam system. The staff verified that the EDB had been appropriately used to identify SSCs within the scope of license renewal and that the applicant had identified and highlighted system piping and instrumentation diagrams to develop the system boundaries in accordance with the procedural guidance. The applicant was knowledgeable of the process and conventions for establishing boundaries as defined in the license renewal implementation procedures. Additionally, the staff verified that the applicant had performed independent verification of the results in accordance with its governing procedures. Specifically, the marked-up drawings were reviewed by other personnel knowledgeable with the system, and cross-discipline verification and independent reviews of the resultant highlighted drawings were also performed.

Insulation. During the audit, the applicant described the evaluation performed to determine if any insulation installed in the plant was required to support any system intended functions identified during the scoping process. As a result, the staff requested that the applicant describe any intended functions performed by insulation or the basis for determining that insulation (e.g. piping insulation) did not meet the scoping criteria described in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). The applicant stated that the intended function of thermal insulation is to provide thermal resistance, which has been identified as an intended function.

Section 3.5.1.4, “Thermal Insulation,” of BNP-LR-007, “License Renewal Scoping Calculation for Criteria 10 CFR 54.4(a)(2),” states that insulating materials can be credited with reducing piping/equipment heat loads in support of SR room/area cooling systems, with limiting heat transfer into or out of system working fluids, or with limiting temperatures in support of equipment environmental qualification. The applicant stated that thermal insulation within the scope of license renewal under 10 CFR 54.4(a)(2) is identified as a system commodity in Attachment 2 of the calculation. Plant areas and systems where temperature control may be of concern include the drywell, emergency core cooling system (ECCS) pump rooms, cryogenic systems, and heat-traced outdoor piping and components needed for freeze protection. A review of the mechanical component screening result calculations identified three engineered safety feature (ESF) systems (residual heat removal (RHR), high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC)) and the heating, ventilation, and air conditioning (HVAC) control building as the primary systems that credit thermal insulation. To the extent that insulation is relied upon to mitigate the effects or propagation of fire, calculation BNP LR-004 addresses these fire barriers against the 10 CFR 54.4(a)(3) fire protection criteria.

Consumables. During the audit, the applicant described the screening review for certain types of consumable commodities in LRA Section 2.1.2.1, “Mechanical Components.” Section 2.1.2.1(6) states that consumable items were evaluated in accordance with the staff screening guidance of SRP-LR Table 2.1-3, “Specific Staff Guidance on Screening.” The table provides guidance for determining if consumable items should be subject to an AMR. For consumables that are periodically replaced, SRP-LR Table 2.1-3 states that the applicant should identify the standards that are relied on for replacement as part of the methodology description.

For consumables such as packing, gaskets, component seals, and O-rings, the table states that these components may be excluded from an AMR using a clear basis. The table also divides consumables into the following four basic categories: (1) packing, gaskets, component seals, and O-rings; (2) structural sealants; (3) oil, grease, and component filters; and (4) system filters, fire extinguishers, fire hoses, and air packs. The LRA states that screening of consumables was either performed as part of the component AMR or the item was excluded based on the staff’s screening guidance. The applicant’s guidance for performing screening reviews for commodity groups is documented in calculation BNP-LR-002, Revision 0, “Bulk Screening of EDB Equipment Types for License Renewal,” which provides the description and the justification for the methodology used for the bulk screening of tagged components in the EDB. Bulk screening is the ability to render an active/passive determination based on EDB equipment type and provide proposed component intended functions for those equipment types that are passive and long-lived.

The staff selected various applicant’s AMRs and verified that each contained a discussion on the treatment of consumables. The following applicant’s AMRs were reviewed during the staff’s scoping and screening audit and were verified to contain components subject to short-lived/replaceable determinations: BNP-LR-306, 337, 338, 341, 345, 348, 359, 364, 365, and 372. The staff concluded that for the remaining AMRs, no short-lived equipment had been identified.

Conclusion. The staff reviewed the LRA, samples of applicable calculations, procedures, drawings, EDB information, and scoping worksheets. The staff determined that the applicant’s proceduralized methodology was consistent with the description provided in LRA Section 2.1.1 and the guidance contained in SRP-LR Section 2.1. Based on review of information contained in the LRA, the applicant’s detailed scoping implementation procedures, and a sampling review of mechanical scoping results; the staff concluded that the applicant’s methodology for identifying mechanical SSCs within the scope of license renewal meets the requirements of 10 CFR 54.4(a).

2.1.3.1.3 Structural Component Scoping

The applicant described the methodology used for structural scoping in LRA Section 2.1.1 "Scoping;" EGR-NGGC-0502, "System/Structure Scoping for License Renewal;" and BNP-LR-002, "Bulk Screening of EDB Equipment Types for License Renewal." The applicant developed a list of SSCs using the information contained in the EDB. The EDB and the CLB were reviewed to identify structures credited with compliance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The primary source of this information was the component-level classification provided in the EDB. The structure and component intended functions had been used in determination of the quality classification of SCs within the EDB. Systems which contained components determined to meet the requirements of 10 CFR 54.4(a)(1), (a)(2), and (a)(3) were considered within the scope of license renewal.

The EDB contained all SR class components and structures and the majority of other plant components and structures. The EDB also included civil commodities such as doors, supports, and penetrations, and the component location. The applicant included all structures within the scope of license renewal which contained components required to be within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

The applicant conducted a series of additional reviews for 10 CFR 54.4(a)(2) and (a)(3) criteria, documented in a series of calculations, to determine if additional components, civil commodities, or structures were included within the scope of license renewal. All civil components and any component civil functions were assigned to civil commodity groups. The applicant reconciled the commodity types with those in NEI-95-10, the GALL Report, and other facility applications, and added appropriate commodity types. In addition, the applicant reviewed other CLB information such as the UFSAR, the structures' DBD and plant drawings; and walked down all structures utilizing a detailed checklist to determine if additional structures housed any components required for license renewal. The walkdowns also served to identify or confirm the commodity types and materials in each structure. If portions of NSR systems were required for 10 CFR 54.4(a)(2) criteria, the entire system's civil components were placed within the scope of license renewal.

For each structure, the applicant developed a structure scoping worksheet in accordance with calculation BNP-LR-010, "License Renewal Project Scoping Calculation." These worksheets provided a general description of the structure, identified whether the structure was in or out of the scope of license renewal, identified a list of applicable CLB documents, and identified each of the civil intended functions required to support the component functions meeting license renewal scoping criteria.

Conclusion. The staff reviewed the LRA, samples of applicable calculations, procedures, drawings, EDB information, and scoping worksheets. The staff determined that the applicant's proceduralized methodology was consistent with the description provided in LRA Section 2.1.1 and the guidance contained in SRP-LR, Section 2.1. Based on review of information contained in the LRA, the applicant's detailed scoping implementation procedures, and a sampling review of structural scoping results, the staff concluded that the applicant's methodology for identification of structural SSCs within the scope of license renewal met the requirements of 10 CFR 54.4(a).

2.1.3.1.4 Electrical and I&C Component Scoping

Electrical and I&C component scoping was performed using the commodity method and is discussed, along with electrical and I&C component screening, in SER Section 2.1.3.2.3.

2.1.3.2 Screening Methodology

2.1.3.2.1 Mechanical Component Screening

The staff reviewed the screening implementation procedures and a selected sample of the system screening reports to ensure consistent application of the applicant's screening methodology. The applicant developed standard procedure EGR-NGGC-0503, "Mechanical Component Screening for License Renewal," to define the process for performing screening of mechanical components.

The applicant determined the components within the scope of license renewal to be those that performed an intended function without moving parts or without a change in configuration or properties. Active/passive screening determinations were based on the guidance in NEI 95-10, Appendix B. The passive components within the scope of license renewal that were not subject to replacement based on a qualified life or specified time period were identified as requiring an AMR. The determination of whether a passive component within the scope of license renewal has a qualified life or specified replacement time period was based on a review of plant-specific information including the EDB, maintenance programs, and procedures. The applicant identified the component intended functions based on the guidance of NEI 95-10.

The results of the mechanical component screening process were documented in system screening calculations which contained the system intended function boundaries, identified the components subject to screening, and documented the screening results for each system component. The component documentation included the component identification, commodity type, screening results (active or passive), a description, and the intended function. The staff reviewed a sample of the mechanical screening packages assembled by the applicant.

The staff also examined the applicant's implementation of this methodology by reviewing a sample mechanical system, the main steam system, identified as being within the scope of license renewal. The review included the evaluation boundaries and resultant components determined to be within the scope of license renewal, the corresponding component-level intended functions, and the resulting list of mechanical components and commodity groups subject to an AMR.

<u>Conclusion</u>. The staff reviewed the LRA, samples of applicable calculations, procedures, drawings, EDB information, and screening results. The staff determined that the applicant's proceduralized methodology was consistent with the description provided in LRA Section 2.1.2 and the guidance contained in SRP-LR Section 2.1. Based on review of information contained in the LRA, the applicant's detailed screening implementation procedures, and a sampling review of mechanical screening results, the staff concluded that the applicant's methodology for identification of mechanical SCs subject to an aging management review meet the requirements of 10 CFR 54.21(a)(1).

2.1.3.2.2 Structural Component Screening

The applicant initially performed a bulk screening process in accordance with guidance of procedure ENG-NGGC-0506, "Civil/Structural Screening and Aging Management Review for LR" and calculations BNP-LR-002 and BNP-LR-008, "Civil Commodity Types and Bulk Screening of EDB Equipment Types" utilizing component information from the EDB. Calculation BNP-LR-008 also provided a list of the 13 civil intended functions, defined civil equipment types, and provided guidance for active/passive/long-lived determinations. This screening process resulted in typical commodity types pertinent to each structure. In addition, reviews of CLB information and facility walkdowns were conducted. Commodity types were reconciled with NEI 95-10, the GALL Report, and other facility license renewal applications.

Portions of the structures such as walls, beams, and foundations do not have unique identifiers, so the applicant identified structural members which support the intended function(s) that the structure performs via review of structural drawings and walkdowns. These items were assigned to a commodity group.

The applicant developed calculations BNP-LR-0110, "License Renewal Civil Screening for Outside Areas," and BNP-LR-0111, "License Renewal Civil Screening for Primary Containment System," to document the results of the screening effort for each structure. The calculations provided a list of structures and structural components subject to aging management review and described the methodology used to develop that list. The calculations provided a description of each structure, identified the structure and commodity civil intended functions, identified the evaluation boundary, and described all components which were transferred into the system from other disciplines (mechanical, electrical) and other structural systems.

<u>Conclusion</u>. The staff reviewed the LRA, samples of applicable calculations, procedures, drawings, EDB information, and screening results. The staff determined that the applicant's proceduralized methodology was consistent with the description provided in LRA Section 2.1.2 and the guidance contained in SRP-LR Section 2.1. Based on review of information contained in the LRA, the applicant's detailed screening implementation procedures, and a sampling review of structural screening results; the staff concluded that the applicant's methodology for identification of structural SCs subject to an AMR meets the requirements of 10 CFR 54.21(a)(1).

2.1.3.2.3 Electrical and I&C Component Scoping and Screening

The applicant described the methodology used for electrical and I&C scoping in LRA Section 2.1.1, "Scoping;" EGR-NGGC-0505, "Electrical Component Screening and Aging Management Review for License Renewal;" and BNP-LR-002, "Bulk Screening of EDB Equipment Types for License Renewal." The applicant developed a list of SSCs using the information contained within the EDB. The EDB and the CLB were reviewed to identify SSCs credited with compliance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The primary source of this information was the component-level classification provided in the EDB. The system and component intended functions had been used in determination of the quality classification of SCs within the EDB. Systems which contained components determined to meet the requirements of 10 CFR 54.4(a)(1), (a)(2), and (a)(3) were considered within the scope of license renewal.

The applicant identified electrical components contained in the EDB that were determined to be within the scope of license renewal and developed a list of the EDB electrical component types for the systems within the scope of license renewal. The applicant reviewed the UFSAR, plant design drawings, and other documentation to identify additional electrical and I&C systems within the scope of license renewal and subsequently identified the equipment and components within the electrical and I&C systems. The applicant developed a comprehensive list of electrical component types present in the systems and structures within the scope of license renewal. The component types associated with the electrical and I&C systems within the scope of license renewal were organized into commodity groupings, such as circuit breakers, cables, and sensors in accordance with the guidance in NEI 95-10.

The applicant identified electrical and I&C component commodity groups that perform an intended function without moving parts or without a change in configuration or properties in accordance with the requirements of 10 CFR 54.21(a)(1)(i). The applicant identified the components within the passive electrical and I&C component commodity groups which are not subject to replacement based on a qualified life or specified time period in accordance with 10 CFR 54.21(a)(1)(ii). The electrical and I&C commodities which were determined to be within the scope of license renewal and subject to an AMR are as follows:

- non-EQ insulated cables and connections
- electrical portions of electrical and I&C penetration assemblies
- phase buses
- high voltage insulators
- switchyard bus
- transmission conductors

The staff also reviewed the applicant’s approach to scoping and screening of electrical fuse holders in accordance with ISG-05, “Identification and Treatment of Electrical Fuse Holders for License Renewal,” dated March 10, 2003. ISG-05 stated that, consistent with the requirements specified in 10 CFR 54.4(a), fuse holders (including fuse clips and fuse blocks) are considered to be passive electrical components. Fuse holders should be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This staff position only applies to fuse holders that are not part of a larger assembly, but support SR and NSR functions in which the failure of a fuse precludes a safety function from being accomplished.

The EDB contained information on all fuses installed at BSEP. The applicant had reviewed each fuse listed in the EDB to determine whether the fuse was part of a larger assembly. The EDB provided sufficient information concerning the application of the fuses to determine that the majority of fuses were part of a larger assembly. However, the applicant identified a subset of the fuses listed in the EDB that were described with limited information and required further evaluation. The applicant reviewed the point-to-point wiring diagrams for the resulting subset of fuses which provided the actual location and equipment in which the fuses were installed. The applicant determined that all fuses contained within the subset were part of a larger assembly; therefore, the fuseholders were not within the scope of license renewal. The applicant did not identify any fuseholders that were required to be within the scope of license renewal in accordance with ISG-05.

Conclusion. The staff reviewed the LRA, samples of applicable calculations, procedures, drawings, EDB information, and scoping and screening results. The staff determined that the applicant's proceduralized methodology was consistent with the description provided in LRA Sections 2.1.1 and 2.1.2 and the guidance contained in SRP-LR Section 2.1. Based on its review of information contained in the LRA, the applicant's detailed scoping and screening implementation procedures, and a sampling review of electrical and I&C scoping and screening results, the staff concluded that the applicant's methodology for identification of electrical and I&C SSCs within the scope of license renewal and electrical and I&C SCs subject to an AMR meets the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.1.4 Evaluation Findings

The staff's review of the information presented in LRA Section 2.1, the supporting information in the scoping and screening implementation procedures, calculations and reports, and the information presented during the scoping and screening audit formed the basis of the staff's safety determination. The staff verified that the applicant's scoping and screening methodology was consistent with the requirements of the Rule and the staff's position on the treatment of NSR SSCs. On the basis of this review, the staff concluded that there is reasonable assurance that the applicant's methodology for identifying the SSCs within the scope of license renewal and the structures and components requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 Plant-Level Scoping Results

2.2.1 Introduction

In LRA Section 2.1, the applicant described the methodology for identifying the SSCs within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which of the SSCs are required to be included within the scope of license renewal. The staff reviewed the plant-level scoping results to determine whether the applicant had properly identified all plant-level systems and structures relied upon to mitigate DBEs, as required by 10 CFR 54.4(a)(1), or whose failure could prevent satisfactory accomplishment of any of the SR functions, as required by 10 CFR 54.4(a)(2), as well as the systems and structures relied on in safety analysis or plant evaluations to perform a function required by one of the regulations referenced in 10 CFR 54.4(a)(3).

2.2.2 Summary of Technical Information in the Application

In LRA Tables 2.2-1, 2.2-2, and 2.2-3, the applicant provided a list of the plant mechanical systems, structures, and electrical/I&C systems, respectively, identifying those mechanical systems, structures, and electrical/I&C systems that are within the scope of license renewal. Systems and structures that only exist at one unit are marked in the tables, as appropriate. Based on the DBEs considered in the plant's CLB, other CLB information relating to NSR systems and structures, and certain regulated events, the applicant identified those plant-level systems and structures that are within the scope of license renewal, as defined by 10 CFR 54.4.

2.2.3 Staff Evaluation

In LRA Section 2.1, the applicant described its methodology for identifying the systems and structures that are within the scope of license renewal and subject to an AMR. The staff reviewed the scoping and screening methodology and provided its evaluation in SER Section 2.1. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results, as shown in LRA Tables 2.2-1, 2.2-2, and 2.2-3 to confirm that there were no omissions of plant-level systems and structures within the scope of license renewal.

The staff determined whether the applicant properly identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4. The staff reviewed selected systems and structures that the applicant did not identify as falling within the scope of license renewal to verify whether the systems and structures have any intended functions that would require their inclusion within the scope of license renewal. The staff's review of the applicant's implementation was conducted in accordance with the guidance described in SRP-LR Section 2.2, "Plant-Level Scoping Results."

The staff sampled the contents of the UFSAR based on the systems and structures listed in LRA Tables 2.2-1, 2.2-2, and 2.2-3 to determine whether there were systems or structures that may have intended functions within the scope of license renewal, as defined by 10 CFR 54.4, that were omitted from the scope of license renewal. The staff did not identify any omissions.

2.2.4 Conclusion

The staff reviewed LRA Section 2.2 and the supporting information in the UFSAR to determine whether any systems and structures within the scope of license renewal had not been identified by the applicant. The staff's review did not identify any omissions. On the basis of this review, the staff concluded that the applicant properly identified the systems and structures that are within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 Scoping and Screening Results – Mechanical Systems

This section documents the staff's review of the applicant's scoping and screening results for mechanical systems. Specifically, this section discusses the following mechanical systems:

- reactor vessel, internals, and reactor coolant system
- engineered safety features
- auxiliary systems
- steam and power conversion systems

In accordance with the requirements set forth in 10 CFR 54.21(a)(1), the applicant must list and describe passive, long-lived structures and components that are within the scope of license renewal (i.e., those that meet the scoping criteria of the License Renewal Rule) and are subject to an AMR. To verify that the applicant properly implemented its scoping and screening methodology, the staff focused its review on the implementation results. This enabled the staff to confirm that the applicant did not inadvertently omit any mechanical system structures or components that meet the scoping criteria and are subject to an AMR.

Staff Evaluation Methodology. The staff evaluated the information provided in the LRA using the same approach for all mechanical systems. The objective of the staff's review was to determine whether all components and supporting structures for a given mechanical system that meet the scoping criteria specified in the rule were identified by the applicant as being within the scope of license renewal in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components were identified by the applicant as being subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Scoping. To perform its scoping evaluation, the staff reviewed the applicable LRA section and associated component drawings (with the exception of some balance-of-plant (BOP) systems discussed below), focusing on components that were not identified as being within the scope of license renewal. The staff reviewed relevant licensing-basis documents, including the plant's UFSAR, for each mechanical system to determine whether the applicant omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff also reviewed the licensing-basis documents to determine whether the LRA omitted any intended function(s) delineated under 10 CFR 54.4(a). If the review revealed an omission, the staff issued an RAI to resolve the discrepancy.

Screening. After completing its scoping evaluation, the staff reviewed the applicant's screening results. For structures and components with intended functions delineated under 10 CFR 54.4(a), the staff sought to determine whether those structures and components perform their function(s) with moving parts or a change in configuration or properties, or if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that did not meet either of these criteria, the staff sought to confirm that the given structures and components were subject to an AMR as required by 10 CFR 54.21(a)(1). If the review revealed any discrepancies, the staff issued an RAI to resolve them.

Two-Tier Scoping Review Process for BOP Systems. There are 62 mechanical systems in the LRA among which 39 are BOP systems, which include most of the auxiliary systems and all the steam and power conversion systems. The staff performed a two-tier scoping review for these BOP systems.

In the two-tier scoping review, the staff reviewed the LRA and UFSAR description focusing on the system intended function to screen all the BOP systems into two groups based on the following screening criteria:

- safety importance/risk significance
- potential for system failure to cause failure of redundant safety system trains
- operating experience indicating likely passive failures
- systems subject to omissions based on previous LRA reviews

Examples of the safety important/risk significant systems are the instrument air (IA) system, the diesel generator (DG) and support systems, and the service water (SW) system based on the results of Individual Plant Examination (IPE) for Brunswick. An example of a system whose failure could result in common cause failure of redundant trains is a drain system providing flood protection. Examples of systems with operating experience indicating likely passive failures include main steam system, feedwater system, and SW system. Examples of systems with identified omissions in previous LRA reviews include spent fuel cooling system, and makeup water sources to safety systems.

From the 39 BOP systems, the staff selected 24 systems for a detailed (Tier-2) scoping review as described above. For the remaining 15 BOP systems, the staff performed a Tier-1 review of the LRA (that don't require detailed boundary drawings) and UFSAR that would identify apparent missing components for an AMR. However, Tier 2 requires the review of detailed boundary drawings in accordance with SRP-LR NUREG - 1800 Section 2.3. The following is a list of these 15 systems:

- screen wash water system
- turbine building closed cooling water system
- heat tracing system
- service air system
- chlorination system
- potable water system
- area radiation monitoring system
- non-contaminated water drainage system
- extraction steam system
- moisture separator reheater drains system and reheat steam system
- heater drains and miscellaneous vents and drains
- turbine building sampling system
- turbine electro-hydraulic control system
- stator cooling system
- hydrogen seal oil system

The staff verified that there is no risk significant system in the above list by examining the results of the Brunswick IPA. None of the above 15 systems are dominant contributors to core damage frequency (CDF), nor are these systems involved in the dominant initiating events.

<u>Systems Identified for Inspection</u>. By the memorandum dated April 28, 2004, the staff recommended that the inspection be used to verify 10 CFR 54.4(a)(2) scoping results. To implement this recommendation in reviewing the Brunswick LRA, the staff identified several systems for the regional inspection team to include in its scoping and screening inspection. These systems have been included in scope of license renewal by the applicant as a result of the 10 CFR 54.4(a)(2) review. The staff requested that the inspection include a sampling review of the engineering report (if available), plant layout drawings, and other documentation, as well as walk-downs of the plant areas that contain these systems and associated components. The following are the list of systems, which the staff identified for inspection:

- heat tracing system
- moisture separator reheater drains system and reheat steam system
- heater drains and miscellaneous vents and drains

As shown in the inspection report, dated July 12, 2005 (ADAMS accession ML052100315).

> "The inspectors reviewed the applicants screening and scoping analysis for the following non-safety related systems located in proximity to safety related systems to assess the implementation of 10 CFR 54.4(a)(2):

Heat Tracing System
Moisture Separator Reheater Drain System & Reheat Steam System
Heater Drains & Miscellaneous Vents and Drains

The review included the applicant's calculation that assessed the system and component applicability to 10 CFR 54.4(a)(2), applicable plant drawings, and visual examination of the in-plant configuration. The inspectors concluded that the applicant had approriately implemented the criteria of 10 CFR 54.4(a)(2) in identifying these systems as being in-scope for license renewal due to their proximity to other safety related systems."

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

In LRA Section 2.3.1, the applicant identified the structures and components of the reactor vessel, internals, and reactor coolant system that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the reactor vessel, internals, and reactor coolant system in the following sections of the LRA:

- 2.3.1.1 reactor vessel and internals
- 2.3.1.2 neutron monitoring system
- 2.3.1.3 reactor manual control system
- 2.3.1.4 control rod drive hydraulic system
- 2.3.1.5 reactor coolant recirculation system

The corresponding subsections of this SER (2.3.1.1 – 2.3.1.5, respectively) present the staff's review findings with respect to the reactor vessel, internals, and reactor coolant system for Units 1 and 2.

2.3.1.1 Reactor Vessel and Internals

2.3.1.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.1, the applicant described the reactor vessel and internals. The reactor pressure vessel (RPV) is a vertical, cylindrical pressure vessel with hemispherical heads and is of welded construction. The major safety consideration for the reactor vessel is the ability of the vessel to function as a radioactive material barrier. The vessel also provides a floodable core volume and provides support for the reactor vessel internals. The RPV contains the RPV internals, consisting of the following: reactor core shroud and support structure; steam separators and dryers; jet pump assemblies; control rod guide tubes; distribution lines for the feedwater, core spray, and standby liquid control systems; the incore instrumentation; and associated components. The purposes of the RPV internals are to properly distribute the flow of coolant delivered to the RPV, to locate and support the fuel assemblies and other internal components, and to provide an inner volume containing the core that can be flooded following a break in the nuclear system process barrier external to the reactor vessel. In addition, the reactor vessel and internals include connected piping that is part of the RCPB.

The reactor vessel and internals contain SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the reactor vessel and internals could potentially prevent the satisfactory accomplishment of an SR function. In addition, the reactor vessel and internals perform functions that support FP, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)
- provides structural support/seismic integrity
- provides post-accident containment, holdup, and plateout of MSIV bypass leakage
- provides adequate flow in a properly-distributed spray pattern

In LRA Table 2.3.1-1, the applicant identified the following reactor vessel and internals component types that are within the scope of license renewal and subject to an AMR:

- top head enclosure (top head)
- top head enclosure [nozzles (vent, top head spray or RCIC, and spare)]
- top head enclosure (head flange)
- top head enclosure (closure studs and nuts)
- vessel shell (vessel flange)
- vessel shell (upper shell)
- vessel shell (intermediate nozzle shell)
- vessel shell (intermediate beltline shell)
- vessel shell (lower shell)
- vessel shell (beltline welds)
- vessel shell (attachment welds)
- nozzles (main steam)
- nozzles (feedwater)
- nozzles (control rod drive (CRD) return line)
- nozzles (recirculation outlet)
- nozzles (recirculation inlet)
- nozzles (low pressure core spray (LPCS) - Unit 1)
- nozzles (LPCS - Unit 2)
- nozzles (shell flange)
- nozzles safe ends (LPCS)
- nozzles safe ends (CRD return line)
- nozzles safe ends (recirculation water inlet and outlet)
- nozzles safe ends (feedwater - Unit 1)
- nozzles safe ends (feedwater - Unit 2)
- nozzles safe ends (standby liquid control)
- nozzles safe ends (instrumentation)
- penetrations (CRD stub tubes)
- penetrations (instrumentation)
- penetrations (jet pump instrument)
- penetrations (standby liquid control)
- penetrations (flux monitor)
- penetrations (drain line)

- reactor vessel (boiling water reactor) (bottom head)
- reactor vessel (boiling water reactor) (support skirt and attachment welds)
- thermal sleeves (feedwater - Unit 1)
- thermal sleeves (feedwater - Unit 2)
- thermal sleeves (LPCS)
- core shroud and core plate [core shroud (upper, central, lower)]
- core shroud and core plate (core plate)
- core shroud and core plate (core plate bolts)
- core shroud and core plate (access hole cover)
- core shroud and core plate (shroud support structure)
- core shroud and core plate (core plate plugs)
- core shroud and core plate (top guide)
- core spray lines and spargers (core spray lines headers)
- core spray lines and spargers (spray rings)
- core spray lines and spargers (spray nozzles)
- core spray lines and spargers (thermal sleeves)
- jet pump assemblies (thermal sleeve)
- jet pump assemblies (inlet header)
- jet pump assemblies (riser brace arm)
- jet pump assemblies (holddown beams)
- jet pump assemblies (inlet elbow)
- jet pump assemblies (mixing assembly)
- jet pump assemblies (diffuser)
- jet pump assemblies (castings)
- jet pump assemblies (jet pump sensing line)
- jet pump assemblies (jet pump holddown beam keeper, lock plate, and bolt)
- fuel supports and CRD assemblies (orificed fuel support)
- fuel supports and CRD assemblies (CRD housing)
- reactor vessel internals (boiling water reactor – NSR) (steam dryer)
- reactor vessel internals (boiling water reactor – NSR) (shroud head and separators)
- reactor vessel internals (boiling water reactor – NSR) (feedwater spargers)
- reactor vessel internals (boiling water reactor – NSR) (surveillance capsule holder)
- piping and fittings (main steam)
- piping and fittings (feedwater)
- piping and fittings (small bore piping less than nominal pipe size (NPS) 4)
- piping and fittings (reactor vessel head vent components)
- valves (body)
- non-RCPB (boiling water reactor) (piping and fittings)
- non-RCPB (boiling water reactor) (valves)
- non-RCPB (boiling water reactor) (piping specialties)
- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)
- air receiver (shell access cover)

2.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1 and UFSAR Sections 3.9.5, 4.5-4.6, and

5.1-5.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3, “Scoping and Screening Results - Mechanical Systems.”

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff’s review of LRA Section 2.3.1.1 identified areas in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The applicant responded to the staff’s RAIs as discussed below.

In RAI 2.3.1.1-1, dated April 8, 2005, the staff stated that UFSAR Section 3.9.5.1.1 states that the core shroud is reinforced at the upper shroud/top fuel guide support ring/middle shroud interface with twelve brackets located at 30 degree intervals starting at the 15 degree azimuth. These brackets provide structural integrity across the interface and compensate for cracking in the heat-affected zones of the original fabrication welds. Therefore, the staff requested that the applicant indicate whether the top fuel guide support ring and middle shroud interface brackets have been included in scope of license renewal or justify the exclusion of these components. In its response, by letter dated May 4, 2005, the applicant stated:

> These components are in scope. The 12 brackets are evaluated as "Core Shroud and Core Plate (Core Shroud Repair Hardware)" and the subcomponents of the Core Shroud are evaluated as "Core Shroud and Core Plate (Core Shroud (Upper, Central, Lower))" as shown in Table 2.3.1-1 on page 2.3-6 of the LRA.

Based on the inclusion of the above components, the staff’s concern described in RAI 2.3.1.1-1 is resolved.

In RAI 2.3.1.1-2, dated April 8, 2005, the staff stated that UFSAR Section 3.9.5.1.3 states that a thermal sleeve is inserted into the control rod drive housing (CRDH) from below and is rotated to lock the control rod guide tube in place. A key is inserted into a locking slot in the bottom of the CRDH to hold the thermal sleeve in position. Therefore, the staff requested that the applicant indicate whether the CRDH thermal sleeve is included in the scope of license renewal or justify its exclusion. In its response, by letter dated May 4, 2005, the applicant stated:

> This subcomponent is in scope but is below the level of detail presented in the AMR tables. See page 2.3-2 of the LRA - "Control Rod Drive (CRD) equipment.” Similar to other subcomponents that comprise the Reactor Vessel Internals, the applicable aging management programs are Water Chemistry and Reactor Vessel and Internals Structural Integrity.

Based on the inclusion of the above component, the staff’s concern described in RAI 2.3.1.1-2 is resolved.

In RAI 2.3.1.1-3, dated April 8, 2005, the staff requested that the applicant indicate whether thermal sleeves for recirculation inlet nozzles are considered part of reactor vessel nozzles, nozzle safe ends and/or instrumentation penetrations requiring an AMR. The subject components represent a pressure boundary and direct flow to core spray spargers and jet pumps. In its response, by letter dated May 4, 2005, the applicant stated:

> The thermal sleeve is evaluated as "Jet Pump Assemblies (Thermal Sleeve)" as shown in Table 2.3.1-1 on page 2.3-6 of the LRA. The associated AMR line items are shown on pages 3.1-58 and 3.1-59 of the LRA. Note: Flow from the Reactor Pressure Vessel (RPV) Recirculation Inlet Nozzles, i.e., Nozzles N2A through N2K, directs flow only to the Jet Pumps. Flow to the Core Spray Spargers is through the Core Spray Nozzles, i.e., N5A and N5B.

Based on the inclusion of the above component, the staff’s concern described in RAI 2.3.1.1-3 is resolved.

In RAI 2.3.1.1-4, dated April 8, 2005, the staff stated that the differential pressure and liquid control line serves a dual function within the reactor vessel: (1) to inject liquid control solution into the coolant stream, and (2) to sense the differential pressure across the core support assembly. Therefore, the staff requested that the applicant indicate whether the subject component is considered part of reactor vessel nozzles, nozzle safe ends and/or instrumentation penetrations requiring an AMR. In its response, by letter dated May 4, 2005, the applicant stated:

> The core differential pressure and standby liquid control (SLC) lines within the vessel are not within the scope of license renewal. On May 15, 1998, the BWR Vessel and Internals Program (BWRVIP) issued "Appendix B, BWR Standby Liquid Control System Core Plate Delta P Inspection and Flaw Evaluation Guideline, Demonstration of Compliance with the Technical Information Requirements of the License Renewal Rule (10 CFR 54.21)." Refer to letter from V. Wagoner, BWRVIP Integration Committee, to C. Carpenter, (NRC), (Serial: 98-185), "License Renewal Appendix B to BWR Vessel and Internals Project, BWR Standby Liquid Control System Core Plate Delta P Inspection and Flaw Evaluation Guideline (BWRVIP-27), April, 1997," dated May 15, 1998, for further information. LRA Section B.2 discusses the components subject to an AMR. Regarding differential pressure/standby liquid control (ΔP/SLC) lines, it states:
>
>> The only ΔP/SLC components required to accomplish the intended function are the vessel penetration/nozzle and SLC external piping. The ΔP/SLC internals piping is not within the license renewal evaluation boundary because it is not required to accomplish the intended function. Therefore, an aging management review of the internals piping is not needed for license renewal.
>
> In Section 2.1 of the NRC Safety Evaluation (SE) for the License Renewal version of BWRVIP-27, it states:
>
>> In Appendix B, the BWRVIP identified the passive and long-lived components as required by 10 CFR 54.21(a)(1). The BWRVIP noted that the ΔP/SLC vessel penetration/nozzle and safe-end extensions are subject to aging management review.

> The NRC SE was provided by letter from C. Grimes, (NRC), to C. Terry, (BWRVIP), "Acceptance for Referencing of Report, 'BWR Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines (BWRVIP-27),' for Compliance with the License Renewal Rule (10 CFR Part 54)," dated December 20, 1999.
>
> In Section 3.1 of the SE, it states:
>
>> The staff agrees that the ΔP/SLC vessel penetration/nozzle and safe-end extensions are subject to aging management review because they perform intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement based on a qualified life or specified time period. The staff concludes that BWR applicants for license renewal must identify the appropriate subject RPV internal components as subject to aging management to meet the applicable requirements of 10 CFR 54.21 (a)(1).
>
> The .P/SLC vessel penetration/nozzle is evaluated as part of "Penetrations (Standby Liquid Control)" and the safe-end is evaluated as "Nozzle Safe Ends (Standby Liquid Control)." These commodities are shown in Table 2.3.1-1 on page 2.3-5 of the LRA. The associated AMR line items appear in Table 3.1.2-1 on pages 3.1-34, 3.1-40, and 3.1-41 of the LRA.

Based on the explanation provided above, the staff’s concern described in RAI 2.3.1.1-5 is resolved.

In RAI 2.3.1.1-5, dated April 8, 2005, the staff stated that the two 100 percent-capacity core spray lines separately enter the reactor vessel through the two core spray nozzles. Each line divides immediately inside the reactor vessel. The two halves are routed to opposite sides of the reactor vessel and are supported by clamps attached to the vessel wall. The header halves are then routed downward into the downcomer annulus and pass through the upper shroud immediately below the flange. The flow divides again as it enters the center of the semi-circular sparger ring which is routed halfway around the inside of the upper shroud. The ends of the two sparger rings for each line are supported by slip-fit brackets designed to accommodate thermal expansion of the rings. The header routing and supports are designed to accommodate differential movement between the shroud and the vessel. Therefore, the staff requested that the applicant indicate whether the core spray clamps which are attached to the vessel wall and the slip-fit brackets which support the ends of the two sparger rings are included in the scope of license renewal requiring an AMR or justify their exclusion. In its response, by letter dated May 4, 2005, the applicant stated:

> The components described are within the scope of License Renewal. The Core Spray Bracket is evaluated as part of "Vessel Shell (Attachment Welds)" as shown in Table 2.3.1-1 on page 2.3-5 of the LRA. The associated AMR line items appear in Table 3.1.2-1 on pages 3.1-22 and 3.1-23 of the LRA. The slip-fit brackets which support the ends of the two sparger rings are evaluated as part of "Core Shroud and Core Plate (Core Shroud (Upper, Central, Lower))" as shown in Table 2.3.1-1 on page 2.3-6 of the LRA. The associated AMR line items appear in Table 3.1.2-1 on pages 3.1-46 and 3.1-47 of the LRA.

Based on the inclusion of the above component, the staff's concern described in RAI 2.3.1.1-5 is resolved.

In RAI 2.3.1.1-6, dated April 8, 2005, the staff stated that its position on reactor vessel flange leak-off lines is that unless a plant-specific justification is provided, the components should be within scope requiring aging management. Therefore, the staff requested that the applicant confirm whether any of the component types listed in LRA Table 2.3.1-1, "Reactor Vessel and Internals," include the subject component. If not, then the subject components should be identified as within scope requiring aging management or provide a plant-specific justification for the exclusion. In its response, by letter dated May 4, 2005, the applicant stated:

> The vessel flange leak detection line is within the scope of License Renewal. The vessel flange leak detection line is evaluated as part of "Non-Reactor Coolant Pressure Boundary (Boiling Water Reactor) (Piping and Fittings)" and "Non-Reactor Coolant Pressure Boundary (Boiling Water Reactor) (Valves)" as shown in Table 2.3.1-1 on page 2.3-7 of the LRA. The associated AMR line items appear in Table 3.1.2-1 on pages 3.1-75, 3.1-76, and 3.1-77 of the LRA. The vessel flange leak detection line is discussed in Section 3.1.2.2.4.2 on page 3.1-8 as follows:
>
>> The reactor vessel flange leak detection line at BSEP is a Class 2 line that is normally dry. The BSEP AMR methodology assumed that this stainless steel line is exposed to treated water and, therefore, is susceptible to cracking due to stress corrosion cracking. This aging effect will be managed with a combination of the Water Chemistry Program and the One-Time Inspection Program.
>
> Further, the vessel flange leak detection line is discussed in the context of responding to Applicant Action Item 4 to BWRVIP-74-A on page B-78 of the LRA as follows:
>
>> The vessel flange leak detection lines are not part of the reactor coolant pressure boundary and as such are not evaluated against Chapter IV of NUREG-1801. These lines (associated with Nozzle N13) are within the scope of License Renewal and are evaluated with all other non-reactor coolant pressure boundary piping and fittings. The AMR for these lines concluded that these lines are susceptible to cracking and loss of material. These lines will be managed by the Water Chemistry and One-Time Inspections Programs.

Based on the inclusion of the above component within the scope of license renewal, the staff's concern described in RAI 2.3.1.1-6 is resolved.

In RAI 2.3.1.1-7, dated April 8, 2005, the staff stated that at BSEP the steam separators are attached to the top of stand pipes which are welded into the shroud head. Therefore, the staff requested that the applicant indicate whether the subject component is included in LRA Table 2.3.1-1 component group "Reactor Vessel Internals (Boiling Water Reactor - Non-safety Related) (Shroud Head and Separators)." In its response, by letter dated May 4, 2005, the applicant stated: "This subcomponent of the shroud head and separators is within the scope of License Renewal and is evaluated as part of 'Reactor Vessel Internals (Boiling Water Reactor-Non-safety Related) (Shroud Head and Separators).'"

Based on the inclusion of the above component within the scope of license renewal the staff's concern described in RAI 2.3.1.1-7 is resolved.

2.3.1.1.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the reactor vessel and internals components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the reactor vessel and internals components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Neutron Monitoring System

2.3.1.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.2, the applicant described the neutron monitoring system (NMS). The NMS is an in-core neutron monitoring system, which detects and monitors neutron flux in the reactor core. The NMS is designed to (1) detect conditions in the core that threaten the overall integrity of the fuel barrier due to excessive power generation and to provide signals to the reactor protection system, so that the release of radioactive materials from the fuel barrier is limited, (2) provide information for the efficient, expedient operation and control of the reactor, and (3) prevent reactor coupled neutronic/thermal-hydraulic instabilities from occurring. The NMS provides the capability to shutdown the reactor via the reactor protection system (RPS) following a DBE and maintains it in a safe shutdown condition. The NMS is composed of the following subsystems: (1) source range monitoring (SRM) subsystem, (2) intermediate range monitoring subsystem, (3) local power range monitoring (LPRM) subsystem, which includes the period-based detection system feature, (4) average power range monitoring subsystem, which includes the oscillation power range monitor subsystem, (5) rod block monitor subsystem, and (6) traversing incore probe (TIP) subsystem.

The NMS contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the NMS could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary.

In LRA Table 2.3.1-2, the applicant identified the following NMS component types that are within the scope of license renewal and subject to an AMR:

- instrumentation (incore neutron flux monitor guide tubes)
- non-RCPB (BWR) (piping and fittings)
- non-RCPB (BWR) (valves)
- non-RCPB (BWR) (piping specialties)

2.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.2 and UFSAR Section 7.6.1.1 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.1.2.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the NMS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the NMS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Manual Control System

2.3.1.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.3, the applicant described the reactor manual control system (RMCS). The RMCS allows the operator to control core reactivity by inserting and withdrawing control rods. The system consists of the electrical components and logic circuits required to monitor and manipulate the control rods. The RMCS also acts to block rod motion and/or selection in response to protective signals generated by other plant monitoring systems. Supporting the RMCS is the rod position information system (RPIS) which provides the operator with a means for determining the positions of all control rods in the core and for observing the position of a selected rod in relation to specific adjacent rods. The RPIS also provides rod position and identification data to the process computer. The RPIS is considered as a subsystem of RMCS. The function of the rod worth minimizer (RWM) system, another RMCS subsystem, is to implement features that provide (1) protection against the existence of a rod worth which could result in significant fuel damage in the unlikely event of a control rod drop accident, (2) implementation of the banked position withdrawal sequence as a hard-wired system, and (3) provision of several rod position indication data and control rod testing functions.

The failure of NSR SSCs in the RMCS could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.1-3, the applicant identified the non-RCPB (BWR) (piping and fittings) as the RMCS component type that is within the scope of license renewal and subject to an AMR.

2.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3 and UFSAR Section 7.7.1.8 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.1.3.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RMCS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RMCS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Control Rod Drive Hydraulic System

2.3.1.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.4, the applicant described the CRD hydraulic system. The CRD hydraulic system supplies the pressure to and controls the flow requirements of the control rod drives. The CRD hydraulic system supplies water at the proper pressures and in sufficient flow to the hydraulic control units (HCU). Each HCU controls the flow to and from a CRD. The water discharged from the drives during a scram flows through the HCU to the scram discharge volume. During a normal control rod positioning operation, the water discharged from a drive flows through its HCU and exhaust header to the cooling water header. The control rod drive hydraulic supply and discharge subsystems control the pressure and flows required for the operation of the CRD mechanisms and also to supply backfill flow to the cold reference legs for reactor vessel level instrumentation. The CRD hydraulic system is an open loop system consisting of two CRD water pumps, two drive water filters, a flow control station, a drive water pressure control station, hydraulic control units for each of the 137 CRD mechanisms, a scram discharge volume, interconnecting piping, associated valves, controls and instrumentation. Reactor coolant pressure-retaining portions of the CRD units attached to the RPV are considered part of the reactor vessel and internals system. The safety objective of the CRD hydraulic system is to insert control rods to provide a means of rapid reactor shutdown, thus limiting damage to the fuel barrier and primary system pressure.

The CRD hydraulic system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the CRD hydraulic system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the CRD hydraulic system performs functions that support EQ and ATWS

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides structural support/seismic integrity

In LRA Table 2.3.1-4, the applicant identified the following CRD hydraulic system component types that are within the scope of license renewal and subject to an AMR:

- non-RCPB (BWR) (piping and fittings)
- non-RCPB (BWR) (valves)
- non-RCPB (BWR) (piping specialties)
- hydraulic control units (tanks)
- hydraulic control units (rupture disks)
- hydraulic control units (nitrogen fittings)
- hydraulic control units (filters)
- hydraulic control units (miscellaneous piping)
- CRD pumps (CRD pump casing)
- CRD pumps (CRD pump gearbox coolers)
- CRD pumps (CRD pump skid piping and valves)
- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)

2.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4 and UFSAR Sections 3.9.4 and 4.6 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.1.4.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the CRD hydraulic system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CRD hydraulic system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.5 Reactor Coolant Recirculation System

2.3.1.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.1.5, the applicant described the reactor coolant recirculation system. The reactor coolant recirculation system regulates coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The reactor coolant recirculation system consists of two recirculation pump loops external to the reactor vessel that provide the piping path for the driving flow of water to the reactor vessel internal jet pumps. Each external loop contains one high-capacity, motor-driven recirculation pump and three motor-operated gate valves for pump maintenance. Each pump discharge line contains a venturi-type flowmeter nozzle. The recirculation loops are a part of the nuclear system process barrier and are located inside the drywell. The arrangement of the recirculation system is such that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel. To support ECCS following a loss-of-coolant accident (LOCA), the recirculation pump discharge valves close automatically to direct low pressure coolant injection (LPCI) flow upward through the jet pump drive lines and into the core floodable volume.

The reactor coolant recirculation system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the reactor coolant recirculation system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the reactor coolant recirculation system performs functions that support FP, EQ, and ATWS.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.1-5, the applicant identified the following reactor coolant recirculation system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (recirculation)
- piping and fittings (small bore piping less than NPS 4)
- recirculation pump (casing)
- recirculation pump (cover)

- recirculation pump (seal flange)
- recirculation pump (closure bolting)
- valves (body)
- non-RCPB (BWR) (piping and fittings)
- non-RCPB (BWR) (valves)
- non-RCPB (BWR) (piping specialties)
- non-RCPB (BWR) (piping and fittings - closed cooling water)

2.3.1.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4 and UFSAR Section 5.4.1 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.1.5.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the reactor coolant recirculation system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the reactor coolant recirculation system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features Systems

In LRA Section 2.3.2, the applicant identified the structures and components of the ESFs systems that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the ESFs systems in the following sections of the LRA:

- 2.3.2.1 residual heat removal system
- 2.3.2.2 containment isolation system
- 2.3.2.3 containment atmospheric control system
- 2.3.2.4 high pressure coolant injection system
- 2.3.2.5 automatic depressurization system

- 2.3.2.6 core spray system
- 2.3.2.7 standby gas treatment system
- 2.3.2.8 standby liquid control system
- 2.3.2.9 hvac control building system
- 2.3.2.10 reactor protection system

The corresponding subsections of this SER (2.3.2.1 – 2.3.2.10, respectively) present the staff's review findings with respect to the ESFs systems for Units 1 and 2.

2.3.2.1 Residual Heat Removal System

2.3.2.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.1, the applicant described the RHR system. The RHR system operates in several modes to remove heat from plant systems or to provide water to plant systems during normal and post-accident conditions. The functions of LPCI, suppression pool cooling, and drywell spray cooling are SR and, therefore, are RHR system intended functions for license renewal. The RHR system functions of normal shutdown cooling, spent fuel pool cooling, torus spray, hydrogen mixing (via containment sprays), supplying water to systems via the SW system cross-connect, and RHR system leak detection are not SR and, therefore, are not RHR system intended functions. In order to minimize the possibility of a single event causing the loss of the entire RHR system, the system is divided into two loops which are physically separated from each other. One loop, consisting of one heat exchanger, two main system pumps in parallel, and associated piping, is located in one area of the reactor building. The other heat exchanger, pumps, and piping, forming a second loop, are located in another area of the reactor building. Portions of the RHR system maintain the integrity of the RCPB.

The RHR system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the RHR system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the RHR system performs functions that support FP, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)
- provides structural support/seismic integrity
- provides heat transfer
- provides insulation/thermal resistance
- provides adequate flow in a properly-distributed spray pattern

In LRA Table 2.3.2-1, the applicant identified the following RHR system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (LPCI system)
- valves (body)
- piping and fittings (LPCI system and RHR)
- piping and fittings (lines to drywell and suppression chanber spriay system (DSCSS))

- piping and fittings (piping specialties)
- piping and fittings (misc. auxiliary and drain piping and valves)
- pumps (high pressure core spray (HPCS) or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (bowl/casing)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (suction head)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (discharge head)
- valves (check, control, hand, motor operted, and relief valves) (body and bonnet)
- heat exchangers (RHR and LPCI) (tubes)
- heat exchangers (RHR and LPCI) (tubesheet)
- heat exchangers (RHR and LPCI) (shell)
- DSCSS (piping and fittings)
- DSCSS (spray nozzles)
- ECCS (BWR) (ECCS pump suction strainers)
- piping (piping and fittings)
- valves (body and bonnet)
- heat exchanger (shell)
- heat exchanger (channel head and access cover)
- heat exchagner (tubes)
- pump (casing)

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1 and UFSAR Sections 5.4.7 and 6.3 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.2.1 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.2.1-1 dated April 8, 2005, the staff stated that the LPCI coupling was identified in the BWRVIP-06 report as an SR component. It appears, however, that the component was not identified in the LRA as requiring an AMR. Therefore, the staff requested that the applicant indicate whether the subject component is within the scope of license renewal requiring an AMR or justify its exclusion from aging management. In its response, by letter dated May 4, 2005, the applicant stated:

> BSEP does not have a LPCI coupling as defined by BWRVIP-06.

As stated on page B-77of the BSEP LRA:

> BWRVIP-42, "LPCI Coupling Inspection and Flaw Evaluation Guidelines," is not applicable to BSEP. BSEP is a BWR-4 whose low pressure coolant injection function of the Residual Heat Removal System injects into the Reactor Coolant Recirculation system discharge lines rather than injecting directly into the reactor vessel.

Based on the explanation above and the non-applicability of the subject component at BSEP, the staff found the applicant's response acceptable. Therefore, the staff's concern described in RAI 2.3.2.1-1 is resolved.

2.3.2.1.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RHR system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RHR system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Containment Isolation System

2.3.2.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.2, the applicant described the containment isolation system. The containment isolation system is an engineered safety feature (ESF) that provides for the closure or integrity of primary and secondary containment penetrations to prevent leakage of uncontrolled or unmonitored radioactive materials to the environment following postulated accidents. The pressure boundary portions of electrical penetrations and miscellaneous/spare mechanical penetrations that are not associated with a process system are included in the civil structural screening described in LRA Section 2.4. The electrical portions of containment electrical penetrations are included in the electrical screening described in LRA Section 2.5. Systems that include primary containment isolation valves are: reactor vessel and internals, NMS, CRD hydraulic system, reactor water cleanup (RWCU) system, reactor coolant recirculation system, core spray system, standby liquid control system, RHR system, containment atmosphere control system, high pressure coolant injection (HPCI) system, RCIC system, post-accident sampling system, torus drain system, reactor building closed cooling water system, instrument air system, radioactive floor drains system, radioactive equipment drains system, and reactor protection system. The containment isolation valves for these systems are included in the screening results for the above systems described elsewhere in this section. Systems that include secondary containment isolation dampers are: standby gas treatment system and HVAC reactor building system. The containment isolation dampers for these systems were determined to be subject to an AMR and are included in the screening results for the above systems described elsewhere in this section.

Containment isolation system components for the above systems have been screened during the screening of each system that includes containment isolation valves. Therefore, the containment isolation system components that require an AMR are included in the screening results for each system described elsewhere in this SER Section 2.3.

Containment isolation system components for the above systems have been screened during the screening of each system that includes containment isolation valves. Therefore, the containment isolation system components that require aging management review are included in the screening results for each system described elsewhere in this section. No separate listing of containment isolation system components/commodities requiring AMR is provided.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 and UFSAR Sections 6.2.3 and 6.2.4 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.2.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the containment isolation system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the containment isolation system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Containment Atmospheric Control System

2.3.2.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.3, the applicant described the containment atmospheric control (CAC) system. The CAC system consists of three major subsystems: the containment inerting subsystem, the containment atmospheric dilution (CAD) subsystem, and the containment atmospheric makeup subsystem. Of these, only the CAD subsystem is designed to function as an ESF system. Based on NRC guidance to control either hydrogen or oxygen concentration within the flammability limit following a LOCA, the CAD subsystem provides long-term nitrogen makeup to the primary containment to maintain oxygen concentration at or below 5 percent. Since this subsystem is designed to ESF standards, all equipment required for CAD service is designed with suitable redundancy and interconnections such that no single failure of an active component will render the system inoperable. This equipment includes a nitrogen storage vessel, electric liquid nitrogen vaporizers, instrumentation, and appropriate piping, flow control stations, and isolation valves. The CAD subsystem nitrogen supply also provides a backup to the instrument air header in the augmented off-gas (AOG) building upon loss of instrument air for the CAD subsystem. The CAC system supports the capability of purging the primary containment through the standby gas treatment system (SGTS) to reduce pressure resulting from nitrogen addition. In order to limit containment pressure to one half of design pressure, venting through the SGTS can be initiated several days following a LOCA. Purging provides a method for limiting containment pressure and for controlling combustible gas concentrations in the containment.

The CAC system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the CAC system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the CAC system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides flow restriction (throttle)
- provides structural support/seismic integrity

In LRA Table 2.3.2-2, the applicant identified the following CAC system component types that are within the scope of license renewal and subject to an AMR:

- containment atmospheric dilution/control system (valves)
- containment atmospheric dilution/control system (piping and fittings)
- containment atmospheric dilution/control system (piping specialties)
- containment atmospheric dilution/control system (tanks)
- containment atmospheric dilution/control system (pumps)
- containment atmospheric dilution/control system (heat exchangers)

2.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3 and UFSAR Section 6.2.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.2.3.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the CAC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CAC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 High Pressure Coolant Injection System

2.3.2.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.4, the applicant described the HPCI system. Each BSEP unit has a dedicated HPCI system. The HPCI system consists of a steam turbine that drives a constant flow pump, and system piping, valves, controls, and instrumentation. The principal HPCI system equipment is installed in the reactor building. Suction piping comes from the condensate storage tank (CST) and the suppression pool. Injection water is piped to the reactor feedwater pipe at a tee connection. Steam supply for the turbine is piped from a main steam header in the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valves and turbine operation are provided in the control room. If a LOCA occurs, the HPCI system is actuated automatically. The primary purpose of the HPCI system is to maintain reactor vessel inventory after small breaks which do not depressurize the reactor vessel. The HPCI system permits the nuclear plant to be shut down, maintaining sufficient reactor vessel water inventory until the vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which either LPCI or core spray (CS) operation can maintain core cooling. In this manner, the HPCI system provides a means for cooling the core at high pressure for those break sizes which are of such a magnitude that, because of a lack of vessel depressurization, the top of the core would become uncovered before the low pressure standby cooling systems were effective.

The HPCI system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the HPCI system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the HPCI system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides flow restriction (throttle)
- provides structural support/seismic integrity
- provides heat transfer

- provides insulation/thermal resistance

In LRA Table 2.3.2-3, the applicant identified the following HPCI system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (HPCI system)
- piping and fittings (steam line to HPCI and RCIC pump turbine)
- piping and fittings (small bore piping less than NPS 4)
- valves (body)
- piping and fittings (HPCI)
- piping and fittings (lines to SC)
- piping and fittings (lines from HPCI and RCIC pump turbines to torus or wetwell)
- piping and fittings (piping specialties)
- piping and fittings (misc. auxiliary and drain piping and valves)
- piping and fittings (restrictive orifices/flow elements)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (bowl/casing)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (suction head)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (discharge head)
- valves (check, control, hand, motor operated, and relief valves) (body and bonnet)
- emergency core cooling system (BWR) (auxiliary pumps)
- emergency core cooling system (BWR) (misc. tanks and vessels)
- emergency core cooling system (BWR) (steam turbines)
- auxiliary heat exchangers (tubing)
- auxiliary heat exchangers (auxiliary heat exchanger shell/housing)
- auxiliary strainers/filters (auxiliary strainer element)
- auxiliary strainers/filters (auxiliary strainer housing)
- emergency core cooling system (BWR) (ECCS pump section strainers)

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4 and UFSAR 6.3.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.4.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HPCI system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HPCI system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.5 Automatic Depressurization System

2.3.2.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.5, the applicant described the automatic depressurization system (ADS). The ADS provides automatic nuclear system depressurization for small and intermediate breaks so that RHR low pressure coolant injection (LPCI) and the CS system can operate when the HPCI system has not been able to accomplish its function. The relief capacity of the ADS is based on the time required after its initiation to depressurize the nuclear system so that the core can be cooled by LPCI and the CS system. The ADS uses seven nuclear system safety relief valves (SRVs) to relieve high pressure steam to the suppression pool. In support of the ADS function, the SRVs open automatically, after a time delay, upon coincident signals of reactor vessel low water level and discharge pressure indication of the availability of any low pressure cooling system (LPSI or CS). In fulfilling its ESF unction, the ADS provides output signals to automatically open designated safety-relief valves. ADS instrumentation and control circuits activate protective actions and support post-accident monitoring of SR systems.

The ADS contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the ADS could potentially prevent the satisfactory accomplishment of an SR function. In addition, the ADS performs functions that support fire protection, EQ, and SBO.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.2-4, the applicant identified the valves (including check valves and containment isolation) (body and bonnet) as the ADS component type that is within the scope of license renewal and subject to an AMR.

2.3.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5 and UFSAR Section 6.3.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.5.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the ADS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the ADS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.6 Core Spray System

2.3.2.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.6, the applicant described the CS system. The CS system is provided to protect the core by removing decay heat following the postulated design-basis LOCA. The CS system provides adequate cooling for all intermediate and large line break LOCAs without assistance from any other core standby cooling system. The protection provided by the CS system also extends to a small break in which the CRD water pumps, the RCIC system, and the HPCI system all are unable to maintain the reactor vessel water level; but the ADS has operated to reduce the reactor vessel pressure such that LPCI and the CS systems can provide core cooling. The CS system consists of two independent loops. Each loop includes one 100 percent capacity centrifugal pump driven by an electric motor, a spray sparger in the reactor vessel above the core, piping and valves that convey water from the suppression pool to the sparger, and associated instrumentation and controls. Actuation of the CS system results from a low water level in the reactor vessel or coincident high pressure in the drywell and low reactor pressure signals. Portions of the CS system support the integrity of the RCPB.

The CS system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the CS system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the CS system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides flow restriction (throttle)
- provides structural support/seismic integrity

In LRA Table 2.3.2-5, the applicant identified the following CS system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (LPCS system)
- piping and fittings (small bore piping less than NPS 4)
- valves (body)
- piping and fittings (LPCS)
- piping and fittings (lines to SC)
- piping and fittings (piping specialties)
- piping and fittings (misc. auxiliary and drain piping and valves)
- piping and fittings (restrictive orifices/flow elements)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (bowl/casing)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (suction head)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (discharge head)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (body and bonnet)
- emergency core cooling system (BWR) (ECCS pump suction strainers)

2.3.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.6 and UFSAR Section 6.3.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.6.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the CS system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CS system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.7 Standby Gas Treatment System

2.3.2.7.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.7, the applicant described the standby gas treatment system (SGTS). The SGTS provides a means for minimizing the release of radioactive material to the environs by filtering and exhausting the atmosphere from the primary or secondary containment during containment isolation conditions. The suction of the system normally is aligned to draw from the reactor building at elevation 50 feet into which all areas of the reactor building communicate. Elevated release is assured by exhausting to the plant stack. Normally closed suction valves are provided in the flow paths from the drywell and the suppression pool to the SGTS. These valves can be opened only upon operator action. The principal functions of the system are (1) to maintain secondary containment below atmospheric pressure when it is contaminated, for example, following a fuel handling accident, (2) to clean up a contaminated drywell or suppression chamber atmosphere when they are being vented to the atmosphere, (3) to provide a filtered pathway when venting the drywell during nitrogen inerting following a LOCA, and (4) to assist in controlling hydrogen stratification in the reactor building following a LOCA. The SGTS, as a part of the secondary containment isolation system, limits the release of radioactivity to the environs after an accident. The system provides a back-up means of controlling post-LOCA hydrogen inside primary containment by venting of the primary containment through the SGTS. SGTS instrumentation and control circuits actuate ESF functions and support post-accident monitoring of SR systems.

The SGTS contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the SGTS could potentially prevent the satisfactory accomplishment of an SR function. In addition, the SGTS performs functions that support fire protection and EQ.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.2-6, the applicant identified the following SGTS component types that are within the scope of license renewal and subject to an AMR:

- ductwork (equipment frames and housing)

- filters (housing and supports)
- filters (elastomer seals)
- standby gas treatment system (BWR) (piping)
- standby gas treatment system (BWR) (valves)
- standby gas treatment system (BWR) (piping specialties)
- standby gas treatment system (BWR) (instrument tubing)

2.3.2.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.7 and UFSAR Section 6.5.1 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.2.7 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.2.7-1, dated May 18, 2005, the staff requested that the applicant clarify whether all the system components such as, but not limited to, exhaust fan (blower) housings, piping, valve bodies, and damper housings, screens for air intake or exhaust structures, etc., are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated June 14, 2005, the applicant stated:

> The SGTS is safety related, and components required to supports its safety related function are in the scope of license renewal in accordance with 10 CFR 54.4(a). This includes fans and filters, valves, screens at the system intake, as well as ductwork / dampers. Passive, long-lived components are subject to AMR under 10 CFR 54.21(a)(1), and include the filter housings, fan housings, screens, and valve bodies.
>
> The SGTS boundaries at BSEP are fairly limited, generally encompassing the SGTS exhaust fans, filters, and piping and valves. Line items for each of these components are represented in the LRA Table 3.2.2-6. Specifically, fan housings are included under "Ductwork (equipment frames and housings)," and valve bodies are addressed under "Standby Gas Treatment (Boiling Water Reactor) (Valves)." The SGTS system interfaces with the reactor building ventilation system and the containment atmospheric control (CAC) system to accomplish its intended functions. The debris screens on the lines from the drywell and suppression chamber are part of the CAC System, and are addressed in LRA Table 3.2.2-2 under "Piping Specialties," with the M-2 intended function. Reactor

building dampers required to isolate in support of SGTS are part of the reactor building ventilation system and are addressed in LRA Table 3.3.2-22.

Based on its review, the staff found the applicant's response acceptable because the applicant clarified that all applicable system components consisting of exhaust fan (blower) housings, piping, valve bodies, and damper housings, screens for air intake or exhaust structures are within the scope of license renewal in accordance with 10 CFR 54.4(a), and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). Therefore, the staff's concern described in RAI 2.3.2.7-1 is resolved.

2.3.2.7.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the SGTS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SGTS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.8 Standby Liquid Control System

2.3.2.8.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.8, the applicant described the SLC system. The SLC system provides a backup method, independent of the control rods, to establish and maintain the reactor subcritical as the nuclear system cools. Maintaining the nuclear system in a subcritical condition as it cools assures that the fuel barrier will not be threatened by overheating in the unlikely event that too few control rods can be inserted to counteract the positive reactivity effects of a colder moderator. Insertion of control rods is always expected to assure prompt shutdown of the reactor should it be required. However, the SLC system can be manually initiated from the control room to pump a neutron absorber solution of sodium pentaborate into the reactor if the operator believes the reactor cannot be shut down or kept shut down with the control rods. The boron in the solution absorbs thermal neutrons and thereby terminates the nuclear fission chain reaction. The boron solution is piped into the reactor vessel and discharged near the bottom of the core shroud so it mixes with the cooling water rising through the core. The SLC system is credited in AST evaluations with post-LOCA pH control in the suppression pool in order to maintain iodine in solution. Portions of the SLC system support the integrity of the RCPB.

The SLC system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the SLC system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the SLC system performs functions that support ATWS.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.2-7, the applicant identified the following SLC system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (lines to RWC and SLC systems)
- piping and fittings (small bore piping less than NPS 4)
- valves (body)
- piping (piping and fittings)
- solution storage (tank)
- valves (pump suction, relief, injection, containment isolation, and explosive actuated discharge) (body and bonnet)
- injection pumps (casing)
- standby liquid control system (boiling water reactor) (hydraulic accumulator tank)

2.3.2.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.8 and UFSAR Section 9.3.4 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.8.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the SLC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SLC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.9 HVAC Control Building System

2.3.2.9.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.9, the applicant described the HVAC control building system. The HVAC control building system is designed to permit continuous occupancy of the control room area, computer rooms and the electronic workrooms (this multi-room area is also called the control room envelope or emergency zone) under normal operating and postulated design basis accident conditions throughout the life of the plant. The system is designed to ensure that optimum habitability and temperature conditions exist within the various control building areas for the safety of plant personnel and equipment. The HVAC control building system permits continuous occupancy of the control room emergency zone under normal and postulated design-basis accident conditions, including a postulated LOCA, main steam line break (MSLB) accident, or release of chlorine gas or smoke. The system permits access and occupancy of the control room under accident conditions without personnel receiving excessive radiation exposure.

The HVAC control building system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the HVAC control building system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the HVAC control building system performs functions that support fire protection, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)
- provides structural support/seismic integrity
- provides heat transfer

In LRA Table 2.3.2-8, the applicant identified the following HVAC control building system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)
- air receiver (shell and access cover)
- filter (shell and access cover)
- dryer (shell and access cover)
- duct (duct fittings, access doors, damper housings and closure bolts)
- duct (equipment frames and housings, including fan housings)
- duct (flexible collars between ducts and fans)
- duct (seals in dampers and doors)
- air handler heating/cooling (heating/cooling coils)
- piping (piping and fittings)
- filters (housing and supports)
- filters (elastomer seals)

2.3.2.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.9 and UFSAR Sections 6.4 and 9.4.1 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) . The staff did not identify any omissions.

2.3.2.9.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HVAC control building system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC control building system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.10 Reactor Protection System

2.3.2.10.1 Summary of Technical Information in the Application

In LRA Section 2.3.2.10, the applicant described the reactor protection system (RPS). The RPS provides timely protection against the onset and consequences of conditions that are threats to the integrity of the fuel barriers (uranium dioxide sealed in cladding) and of the nuclear system process barrier. Excessive temperature tends to degrade the cladding and/or melt the uranium dioxide. Excessive pressure tends to rupture the nuclear system process barrier. The RPS limits the uncontrolled release of radioactive material from the fuel and nuclear system process barrier by initiating an automatic scram to terminate excessive temperature and pressure increases resulting from high reactor power.

The RPS contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the RPS could potentially prevent the satisfactory accomplishment of an SR function. In addition, the RPS performs functions that support fire protection, EQ, and SBO.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.2-9, the applicant identified the ESFs (misc. non-GALL components (inside)) as the RPS component type that is within the scope of license renewal and subject to an AMR.

2.3.2.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.10 and UFSAR Section 7.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2.10.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RPS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RPS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

In LRA Section 2.3.3, the applicant identified the structures and components of the auxiliary systems that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the auxiliary systems in the following sections of the LRA:

- 2.3.3.1 reactor water cleanup system
- 2.3.3.2 reactor core isolation cooling system
- 2.3.3.3 reactor building sampling system
- 2.3.3.4 post accident sampling system
- 2.3.3.5 circulating water system
- 2.3.3.6 screen wash water system
- 2.3.3.7 service water system
- 2.3.3.8 reactor building closed cooling water (RBCCW) system
- 2.3.3.9 turbine building closed cooling water (TBCCW) system
- 2.3.3.10 diesel generator system
- 2.3.3.11 heat tracing system
- 2.3.3.12 instrument air system

- 2.3.3.13 service air system
- 2.3.3.14 pneumatic nitrogen system
- 2.3.3.15 fire protection system
- 2.3.3.16 fuel oil system
- 2.3.3.17 radioactive floor drains system
- 2.3.3.18 radioactive equipment drains system
- 2.3.3.19 makeup water treatment system
- 2.3.3.20 chlorination system
- 2.3.3.21 potable water system
- 2.3.3.22 process radiation monitoring system
- 2.3.3.23 area radiation monitoring system
- 2.3.3.24 liquid waste processing system
- 2.3.3.25 spent fuel system
- 2.3.3.26 fuel pool cooling and cleanup system
- 2.3.3.27 HVAC diesel generator building
- 2.3.3.28 HVAC reactor building
- 2.3.3.29 HVAC service water intake structure
- 2.3.3.30 HVAC turbine building
- 2.3.3.31 HVAC radwaste building
- 2.3.3.32 torus drain system
- 2.3.3.33 civil structure auxiliary systems
- 2.3.3.34 non-contaminated water drainage system

The corresponding subsections of this SER (2.3.3.1 – 2.3.3.34, respectively) present the staff's review findings with respect to the auxiliary systems for Units 1 and 2.

2.3.3.1 Reactor Water Cleanup System

2.3.3.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.1, the applicant described the reactor water cleanup system (RWCU) system. The RWCU system provides continuous purification of a portion of the reactor recirculation flow. The system can be operated at any time. The major equipment of this system, which is located in the reactor building, consists of pumps, heat exchangers (both regenerative and non-regenerative), two filter-demineralizers, and the associated valves, piping, and instrumentation. Reactor coolant is removed from the reactor coolant recirculation system and is cooled in the regenerative and nonregenerative heat exchangers. After cooling, the circulated water is filtered and demineralized to reduce the amount of activated corrosion products in the water. It is then returned to the feedwater system through the shell side of the regenerative heat exchanger. RWCU is isolated automatically upon initiation of the standby liquid control system and upon detection of conditions that may indicate a pipe break in the RWCU system. These conditions are low reactor vessel water level, high differential flow in RWCU piping, and high room temperature. Portions of the RWCU system support the integrity of the RCPB.

The RWCU system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the RWCU system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the RWCU system performs functions that support EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)
- provides structural support/seismic integrity

In LRA Table 2.3.3-1, the applicant identified the following RWCU system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (lines to RWC and SLC systems)
- piping and fittings (small bore piping less than NPS 4)
- valves (body)
- piping (piping and fittings - beyond second isolation valves)
- regenerative heat exchanger (shell and access cover)
- reactor water cleanup system (BWR) (valves - beyond second isolation vavles)
- RWCU system (BWR) (tanks, pumps, and piping specialties - beyond second isolation valves)

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 and UFSAR Section 5.4.8 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by letter dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.1-1, the staff stated that LRA Table 2.3.3 1 identifies the license renewal intended function for the regenerative heat exchanger (RHX) shell(s) and access cover(s) as structural support and does not identify it as pressure boundary. This is in contrast to all other RWCU components listed in LRA Table 2.3.3 1. Therefore, the staff requested that the applicant provide additional information describing the basis for the RHX shell and access cover intended function in Table 2.3.3 1.

In its response, dated May 4, 2005, the applicant stated that the RWCU heat exchanger forms the termination point for the seismic evaluation of the SR/NSR interface at the valve F042 and that this boundary appears on drawing D-25027-LR, sheet 1B (quadrant E6) for Unit 1 and D-02527-LR, sheet 1A (quadrant E6) for Unit 2.

LRA Section 2.1.1.2 discusses the criteria used for the scope assessments of NSR SSCs pursuant to 10 CFR 54.4(a)(2). The LRA states that for NSR piping connected to SR piping, the NSR piping is included within the scope of license renewal up to either the first seismic anchor past the safety/non-safety interface, or a point where the NSR pipe is restrained in three directions (either by a single support or by individual supports). Since the RWCU RHX 1C shell and access cover are restrained in three directions, the staff concluded that terminating the seismic evaluation of the SR/NSR piping interface at the valve F042 is consistent with SRP-LR, Revision 1, Section 2.1.3.1.2; therefore license renewal function M4 "Provide structural support/seismic integrity" is appropriate for this component.

In its response to RAI 2.3.3.1-1, dated May 4, 2005, the applicant also stated that the RWCU heat exchangers are in a walled area in the reactor building that houses no SR components and is sufficiently isolated/protected from other parts of the reactor building to preclude adverse spatial interactions (i.e., flooding, wetting, and spraying) with SR components elsewhere in the building. The line 1/2-G31-50-4-907 connected to the heat exchanger is partially located outside this discrete area and therefore the M-1 "Provide pressure retaining boundary" function was assigned to this line because of spatial interaction considerations.

Based on its review, the staff found the applicant’s response acceptable. The applicant provided clear criteria and bases for limiting the license renewal function of the RWCU RHX shells and connecting piping to M 4 "Provide structural support/seismic integrity" and for excluding M 1 "Provide pressure retaining boundary." Therefore, the staff’s concern described in RAI 2.3.3.1-1 is resolved.

InRAI 2.3.3.1-2, the staff stated that license renewal boundary drawing D-25027-LR, sheet 1A (quadrant E-4), and drawing D-25027-LR, sheet 1B (quadrant D-3), show Unit 1 RHX shell "1C" and Unit 2 RHX shell "2C" as within the scope of license renewal. However, the remaining Units 1 and 2 RHX shells "1A," "1B," "2A," and "2B" and their associated piping are shown as not within the scope of license renewal. In addition, several piping sections between the RHX shells and a normally closed isolation valve are also shown as not within the scope of license renewal. Therefore, the staff requested that the applicant provide additional information to support its determination that these components and associated piping are not within the scope of license renewal despite the components intended function defined in LRA Section 2.3.3.1.

In its response, by letter dated May 4, 2005, the applicant stated that the NSR RWCU heat exchangers (i.e., "1C" and "2C") form the termination point for the seismic evaluation of the SR/NSR interface at the F042 valve. The RWCU heat exchangers "1A," "1B," "2A," and "2B" are not credited with seismic support. The applicant also confirmed that all the RWCU regenerative heat exchangers are enclosed within a walled area in the reactor building that houses no SR components and is sufficiently isolated/protected from other parts of the reactor building to preclude adverse spatial interactions (i.e., flooding, wetting, and spraying) with SR components elsewhere in the building. Therefore, the "1C" and "2C" NSR RWCU RHX are brought within the scope of license renewal per 10 CFR 54.4(a)(2) but not the other NSR SSCs in the exclusion area.

Based on its review, the staff found the applicant’s response acceptable because the license renewal function of the RWCU regenerative heat exchangers 1C and 2C is to provide structural support/seismic integrity, and the applicant has provided clear criteria and bases for concluding that the failure of any RWCU regenerative heat exchanger shells and connecting piping will not result in spatial interactions with SR equipment per 10 CFR 54.4(a)2. Therefore, the staff’s concern described in RAI 2.3.3.1-2 is resolved.

In RAI 2.3.3.1-3, the staff stated that on sheet 1A of license renewal boundary drawings D-25027-LR and D-02527-LR, it was not clear why the portions of lines 36-3-153 and 51-3-153 from inside the reactor building to valves F035, F034, and F036 are shown as not within the scope of license renewal. Therefore, the staff requested that the applicant provide additional information justifying why these are not within scope and why the scope does not include the remaining non-isolable piping between the inside wall of the secondary containment and the piping adjacent to valves F034, F035, and F036.

In its response, by letter dated May 4, 2005, the applicant stated:

> The portions of the RWCU System within the scope of License Renewal shown on License Renewal Boundary Drawing D-25027-LR, Sheet 1A, Locations B-8 and C- 8, for Unit No. 1 and on License Renewal Boundary Drawing D-02527-LR, Sheet 1A, Locations B-8 and C-8, for Unit No. 2 are related to spatial interaction considerations. The License Renewal boundary flags indicate the transition to the walled area containing the RWCU heat exchangers in the Reactor Building that houses no safety related components and is sufficiently isolated/protected from other parts of the Reactor Building to preclude adverse spatial interactions (i.e., flooding, wetting, and spraying) with safety related components elsewhere in the building.

Based on its review, the staff found the applicant’s response acceptable because the applicant provided clear criteria and bases for concluding that failure of the portions of RWCU components identified in this RAI will not result in spatial interactions with SR equipment per 10 CFR 54.4(a)2. Therefore, the staff’s concern described in RAI 2.3.3.1-3 is resolved.

In RAI 2.3.3.1-4, the staff stated that sheet 1B (quadrant D-6) of license renewal boundary drawings D-25027-LR and D-02527-LR terminate the in-scope portion of line 49-6-907 in the middle of line 65-6-907. Since the portion of 49-6-907 within the scope of license renewal also includes two 3/4-inch capped vent connections, it was not clear why the non-isolable portions of connecting piping would not also be within the scope of license renewal. Therefore, the staff requested that the applicant clarify the reason for terminating the scope at line 65-6-907 and not including the non-isolable portions of connecting piping.

In its response, by letter dated May 4, 2005, the applicant stated that line 1/2-G31-49-6-907 is an NSR line that was brought within the scope of license renewal because it is required to protect the SR/NSR boundary at valve 1/2-G31-F004. The highlighted portions of the license renewal drawings indicate the extent of the piping included in the seismic evaluation. The license renewal flag on line 1/2-G31 49-6-907 indicates the terminus of the seismic evaluation. Based on its review, the staff found the applicant's response acceptable, because the applicant clarified the extent of the piping that is included within the scope of license renewal to protect the SR portions of the system, and it is based on a seismic evaluation. Therefore, the staff's concern described in RAI 2.3.3.1-4 is resolved.

2.3.3.1.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RWCU system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RWCU system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Reactor Core Isolation Cooling System

2.3.3.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.2, the applicant described the RCIC system. The RCIC system consists of a steam-driven turbine pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. The steam supply to the turbine comes from the main steam line upstream of the isolation valves and exhausts to the suppression pool. The pump can take suction from the CST or from the suppression pool. The makeup water is delivered into the reactor vessel through a connection to the feedwater line and is distributed within the reactor vessel through the feedwater sparger. Cooling water for the RCIC system turbine lube oil cooler and gland seal condenser is supplied from the discharge of the pump. The RCIC system operates automatically to maintain sufficient coolant in the reactor vessel to prevent overheating of the reactor fuel in the event of reactor isolation accompanied by loss of feedwater flow. The system functions in a timely manner so that integrity of the radioactive material barrier is not compromised.

The RCIC system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the RCIC system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the RCIC system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides flow restriction (throttle)
- provides structural support/seismic integrity
- provides heat transfer
- provides insulation/thermal resistance

In LRA Table 2.3.3-2, the applicant identified the following RCIC system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (RCIC system)
- piping and fittings (steam line to HPCI and RCIC pump turbine)

- piping and fittings (small bore piping less than NPS 4)
- valves (body)
- piping and fittings (RCIC)
- piping and fittings (lines to SC)
- piping and fittings (lines to HPCI and RCIC pump turbine)
- piping and fittings (lines from HPCI and RCIC pump turbines to torus or wetwell)
- piping and fittings (piping specialties)
- piping and fittings (misc. auxiliary and drain piping and valves)
- piping and fittings (restrictive orifices/flow elements)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (bowl/casing)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (suction head)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (discharge head)
- pumps (HPCS or HPCI main and booster, LPCS, LPCI or RHR, and RCIC) (body and bonnet)
- emergency core cooling system (BWR) (auxiliary pumps)
- emergency core cooling system (BWR) (misc. tanks and vessels)
- emergency core cooling system (BWR) (steam turbines)
- auxiliary heat exchangers (auxiliary heat exchanger tubing)
- auxiliary heat exchangers (auxiliary heat exchanger shell/housing)
- auxiliary strainers/filters (auxiliary strainer housing)
- emergency core cooling system (BWR) (ECCS pump suction strainers)
- pressure regulators (body and bonnet)

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 and UFSAR Sections 5.4.6 and 6.3.2.8 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.2.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RCIC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RCIC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.3 Reactor Building Sampling System

2.3.3.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.3, the applicant described the reactor building sampling (RXS) system. The RXS system monitors plant and equipment performance to determine routine chemical properties and radiation levels necessary to provide information for equipment operation, corrosion control, and radiation activity. The system also provides information for making operational decisions with regard to effectiveness, safety, and proper performance. Samples can be taken continuously or obtained as grab samples. There is one central sampling station that is essentially a package of sample conditioning and analyzing sections and a sample hood. Consideration of accessibility, safe withdrawal, and efficient handling of samples were factored into the design of the centralized sampling station. Portions of this system comprise part of the RCPB. Also, portions of this system are used for primary containment isolation.

The RXS system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the RXS system could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-3, the applicant identified the following RXS system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (sample lines)
- piping (piping and fittings)
- valves (body and bonet)
- heat exchanger (shell and access cover)
- flow orifice (body)
- pump (casing)
- filters (shell and access cover)
- immersion element (pressure-retaining housing)
- tank (shell)

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 and UFSAR Section 9.3.2.1 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.3 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.3-1, dated April 8, 2005, the staff stated that LRA Section 2.3.3.3 states that the RXS system monitors the plant and equipment performance to determine routine chemical properties and radiation levels necessary to provide information for equipment operation, corrosion control, and radiation activity. The following inconsistencies were identified in the LRA for the RXS system.

- The pressure relief valves PRV-207, PRV-208, PRV-209, and PRV-210 and their associated piping on Unit 1 drawing D-70070-LR, sheet 1, at locations D-7, D-5, D-2, and D-1, are not shown as being included within the scope of license renewal. However, the same pressure relief valves and associated piping shown on the Unit 2 drawing D-07070-LR at the same relative locations are shown as being included within the scope of license renewal.
- The piping and isolation valves V132, V133, V134, V135, V136, and V137 on Unit 1 drawing D-70070-LR, sheet 1, at locations D-4 through D-6, are not shown as being included within the scope of license renewal. However, the same piping and isolation valves on the Unit 2 drawing D-07070-LR, sheet 1, at the same relative locations are shown as being included within the scope for license renewal. The piping for pressure indicators PI-5220 (for both Units 1 and 2), PI-5221, PI-5222, and PI-R007A shown on Unit 1 drawing D-70070-LR, sheet 1, at locations D-5 through D-7 are not shown as being included in scope for license renewal. However, the same piping for similar pressure indicators on the Unit 2 drawing D-07070-LR, sheet 1, at the same relative locations are shown as being included in scope for license renewal.

Therefore, the staff requested that the applicant provide additional clarification and justification as to whether the above listed valves and associated piping should be or should not be included in scope for license renewal.

In its response, by letter dated May 4, 2005 the applicant stated that the subject components are within the RXS system license renewal scoping boundary and are subject to an AMR. The staff found the applicant's response acceptable and, therefore, the staff's concern described in RAI 2.3.3.3-1 is resolved.

2.3.3.3.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RXS system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RXS system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.4 Post Accident Sampling System

2.3.3.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.4, the applicant described the post-accident sampling system (PASS). The PASS function is to obtain representative liquid samples from the primary coolant system and gas samples from primary and secondary containment for radiological analysis following an accident, including a LOCA. The basic system consists of a liquid and gas sample station located outside the reactor building in the turbine building breezeway. Each unit has its own sampling system. Each sampling and control station is located near each unit's reactor building personnel access doors. To meet the requirements of NUREG-0578, the design is intended to minimize radiation exposure during sampling by minimizing the required sample sizes, to optimize the weight of shielded sample containers in order to facilitate movement through potentially high-level radiation areas, and to provide adequate shielding at the sample station and in the laboratory. The system is also designed to provide useful samples under all conditions ranging from normal shutdown and power operation. A local area radiation monitor is provided to inform the operator of the ambient radiation level.

The PASS contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the PASS could potentially prevent the satisfactory accomplishment of an SR function. In addition, the PASS performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.3-4, the applicant identified the following PASS component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- heat exchanger (shell and access cover)

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and UFSAR Section 9.3.2.2 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.4 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.4-1, dated April 8, 2005, the staff stated that the in-scope license renewal boundaries identified at quadrant E-5 and E-6 on sheet 1 license renewal boundary drawings D-73027-LR and D-07327-LR terminate in the middle of a pipe run. Therefore, the staff requested that the applicant discuss the basis for terminating the in-scope portion of this piping downstream of solenoid valves SV 4180, SV 4181, SV 4184, and SV 4185 in the middle of the piping runs.

In its response, by letter dated May 4, 2005, the applicant stated that lines 1/2-RXS-2 and 1/2-RXS-20 are NSR lines that were brought within the scope of license renewal because they are required to protect the SR/NSR boundary at valves 1/2-RXS-SV-4180/4181 and 1/2-RXS-SV-4184/4185 respectively. The applicant explained that the license renewal boundaries identified at quadrant E-5 and E-6 on sheet 1 license renewal boundary drawings D-73027-LR and D-07327-LR are associated with stress analyses and represent supports or anchor points that define the extent of in-scope piping credited with providing a structural support/seismic integrity license renewal intended function. Based on its review, the staff found the applicant's response acceptable; therefore, the concern described in RAI 2.3.3.4-1 is resolved.

2.3.3.4.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the PASS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the PASS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.5 Circulating Water System

2.3.3.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.5, the applicant described the circulating water (CW) system. The CW system provides the heat sink necessary to remove the latent heat of condensation from the exhaust steam of the low pressure turbines and to cool the condensate sufficiently to prevent cavitation in the condensate system, thus maintaining the vacuum required for operation. The system also provides the dilution flow necessary for acceptable radioactive liquid effluent release concentrations. The CW system is designed to supply a continuous flow of cooling water to the main condensing system to remove heat rejected from the steam power cycle. The CW system takes suction from the Cape Fear River estuary, provides cooling water through the main condensers, then discharges to the ocean. The CW system also dilutes the liquid waste flow prior to its release to the environment. The CW system is not required to function in order to shutdown the reactor or maintain it in a safe shutdown condition. Some electrical components in the system are classified as seismically analyzed to avoid adverse interactions with SR SSCs during an earthquake.

The failure of NSR SSCs in the CW system could potentially prevent the satisfactory accomplishment of an SR function.

The CW system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5 and UFSAR Section 10.4.5 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.5.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the CW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.6 Screen Wash Water System

2.3.3.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.6, the applicant described the screen wash water (SCW) system. The SCW system consists of twelve traveling screens, four screen wash pumps, and four self-cleaning strainers. This system provides filtering capabilities for the circulating water and SW systems of both units. Intake canal water enters the SW intake structure through trash racks mounted across the inlet bays. Large debris is stopped by the trash racks and accumulates on the upstream face. The traveling screens at the individual pump bays remove the smaller debris and refuse that enters the intake structure. The SCW system is not required for safe shutdown of the unit and does not provide any essential auxiliary service.

The failure of NSR SSCs in the SCW system could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-5, the applicant identified the following SCW system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- pump (casing)
- strainer (body)

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and UFSAR Section 9.2.1.2 using the evaluation methodology described in SER Section 2.3 as related to the “Two-Tier Scoping Review Process for BOP Systems.”

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff’s review of LRA Section 2.3.3.6 identified an area in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The applicant responded to the staff’s RAI as discussed below.

In RAI 2.3.3.6-1, dated April 8, 2005, the staff noted that LRA Section 2.3.3.6 states that the SCW system consists of 12 traveling screens. The four traveling screens associated with the SW system were determined to be within the scope of license renewal, but the screens are active components, not subject to an AMR. The application had not addressed the other eight traveling screens. Therefore, the staff requested that the applicant address the following:

(vvvvvvvvvv) The systems/components having intended functions as identified in 10 CFR 54.4(a) are within the scope of license renewal. Clarify whether the other eight traveling screens are within the scope of license renewal. If not, identify where these eight traveling screens are located and explain the intended functions of the system.

(wwwwwwwwww) Based on the NRC review guidance in SRP-LR Table 2.1-5 and industry guidance, Appendix B to NEI 95-10, Revision 3, for passive/active determination, the screen is not generally included as an active component. The applicant is requested to justify the screen being an active component for Brunswick, or add screens to LRA Table 2.3.3-5 as component requiring an AMR.

(xxxxxxxxxx) Identify all the systems that have screens and were excluded from an AMR based on screens being active.

In its response, by letter dated May 4, 2005, the applicant discussed the bases for its scoping and screening determination for the traveling screens. The applicant stated that traveling screens in the SCW system are provided for trash, fish, and larvae removal to minimize the fouling and clogging of water box tube sheets and piping and to protect fish and larvae. The traveling screens consist of a series of screen panels connected in a continuous loop across rotating drive sprockets. As water flows through the screen panels, debris is collected and held against the screens by the force of flowing water. As debris collects, the pressure differential between the inlet and outlet sides of the screens increases. During normal operations, when the pressure differential reaches the predetermined setpoint, the SW screen rotates and the screen wash pumps wash the debris free.

The eight traveling screens that are not within the scope of license renewal act as filters in the CW system. The CW system provides a condenser cooling function that is not one of the license renewal intended functions specified in 10 CFR 54.4(a). Therefore, the staff agreed with the applicant that these eight traveling screens are not within the scope of license renewal. The four traveling screens act as filters for the SW system, which performs SR functions, and are within the scope of license renewal. These traveling screens are subcomponents of active assemblies, subject to periodic maintenance and replacement, and continuously monitored through control room annunciation. The traveling screens can move at between 2.5 and 20 feet per minute. The staff agreed with the applicant on its determination that these four traveling screens are active, and can be screened out from an AMR in the license renewal screening process. All the twelve traveling screens in BSEP are not subject to an AMR with acceptable justifications. No other type of screen was excluded from the requirement of an AMR on the basis of being classified as "active." Based on its review, the staff found the applicant's response acceptable. Therefore, the staff's concerns described in RAI 2.3.3.6-1 are resolved.

2.3.3.6.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the SCW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SCW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.7 Service Water System

2.3.3.7.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.7, the applicant described the SW system. The SW system provides water from the Cape Fear River for lubrication and cooling of equipment in the reactor building, turbine building, diesel generator building, and the circulating water system, and for dilution flow in the chlorination system. SW can also be cross-connected to the RHR system in an emergency to provide reactor core flooding capability. The SW system is required to operate following a DBE in order to provide cooling water to the diesel generators and to the RHR system for LPCI cooling and to limit the suppression pool temperature during operation of HPCI and RCIC systems. The system also provides cooling water to the CS pump room and RHR pump room coolers. The SW system is subdivided into two major portions, one basically for nuclear and vital loads and the other normally for conventional loads in the turbine building. The two portions of the system are normally operated independently, each consisting of a group of SW pumps, parallel loads, and interconnecting headers. Suitable cross-connecting valves and piping are provided to permit use of the conventional system as a backup supply for reactor building cooling loads. Backup for diesel generator cooling is provided by the nuclear headers of each unit or by cross-connecting conventional header pumps to the nuclear header.

The SW system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the SW system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the SW system performs functions that support fire protection and EQ.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides flow restriction (throttle)
- provides structural support/seismic integrity
- provides heat transfer

In LRA Table 2.3.3.7, the applicant identified the following SW system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- piping (underground piping and fittings)
- piping (piping specialties)
- valves (body and bonnet)
- heat exchanger (SW pump motor cooler coils)
- flow orifice (body)

- pump (casing)
- basket strainer (body)
- CW strainer (body only)

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7 and UFSAR Section 10.4.7 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.7 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.7-1, the staff stated that License renewal drawing D-02041-LR, sheet 1, location F-2, has strainer 2-SW-ST-3 within the scope of license renewal; however, strainer 2-SW-ST-2 is not within the scope of license renewal. Therefore, the staff requested that the applicant explain why strainer 2-SW-ST-2 is not within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that 2-SW-ST-2 was inadvertently omitted from highlighting. This component is in the scope of license renewal, and was subject to an AMR.

Based on its review, the staff found the applicant's response acceptable because the applicant had concluded that 2-SW-ST-2 is within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.7-1 is resolved.

In RAI 2.3.3.7-2a and 2b, the staff stated that license renewal drawings D-02041-LR, sheet 1, location F-1, has an LRA flag in the middle of a section of pipe which is continued on D-2041-3. Similarly, license renewal drawing D-20041-LR, sheet 1, location F-8, has an LRA flag in the middle of a section of pipe which is continued on D-20041, sheet 3. Therefore, the staff requested that the applicant explain why the LR scope boundary occurs in the middle of these sections of pipe.

In its response, by letter dated May 4, 2005, the applicant stated that the subject lines supply cooling water to the circulating water pumps. They are NSR, but the portion of the lines inside the SW building are within the scope of license renewal for potential spatial interaction. The boundary flag represents the location where the line exits the SW intake structure.

Based on its review, the staff found the applicant's response acceptable, because the NSR lines within the SW intake structure are included within scope for potential spatial interaction. The LRA boundary flag is placed where the lines exit the SW intake structure where spatial interaction is not a concern. Therefore, the staff's concerns described in RAI 2.3.3.7-2a and 2b are resolved.

In RAI 2.3.3.7-3a and 3b, the staff stated that license renewal drawing D-02041-LR, sheet 1, locations A-8, A-6, and A-3, depict three lines each from the conventional header SW pumps with continuations on drawing F-4024. Drawing F-4024 was not provided with the LRA. Similarly, license renewal drawing D-20041-LR, sheet 1, locations B-1, B-6, and B-3, depict three lines each from the conventional header SW pumps with continuations on drawing F-04024. Drawing F-04024 was not provided with the LRA. Therefore, the staff requested that the applicant provide additional information on where the LRA boundary was located for these sections of pipe.

In its response, by letter dated May 4, 2005, the applicant stated that the subject lines are the seal leak off and lube oil cooler discharge lines on the conventional SW pumps. They are within scope to provide a discharge flow path in support of the operation of the pumps. All six lines discharge into an open hub drain, which drains directly down into the pump intake bay. Failure of the hub drain itself and the short run of pipe back to the pump bay could not obstruct the flow path of these lines, nor otherwise present a liability to the pump or nearby SR equipment. As such, the hub drains and piping depicted on F-4024 do not perform an intended function that satisfies any one of the 10 CFR 54.4 criteria and, therefore, are not within the scope of license renewal.

Based on its review, the staff found the applicant's response acceptable because all six lines discharge into an open hub drain, which drains directly down into the pump intake bay. Failure of the hub drain itself and the short run of pipe back to the pump bay could not obstruct the flow path of these lines, nor otherwise present a liability to the pump or nearby SR equipment. Therefore, the staff's concerns described in RAI 2.3.3.7-3a and 3b are resolved.

In RAI 2.3.3.7-4a and 4b, the staff stated that license renewal drawing D-02034-LR, sheet 1, locations F-2, and E-2, depict five drains, which include valves 2-SW-V444, V95, 2-SW-663, 2-SW-669, and 2-SW-664 that are not within the scope of license renewal. Similarly, license renewal drawing D-20034-LR, sheet 2, locations F-7, and D-8, depicts five drains which include valves 1-SW-V444, V95, 2-SW-663, 2-SW-669, and 2-SW-664 that are not within the scope of license renewal. Therefore, the staff requested that the applicant explain why these sections of pipe and valves are not within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the subject piping/components are attached to the 36-inch SW discharge line. The NSR SW discharge line is within the scope of license renewal for providing a discharge flow path from SR components in the reactor building to the CW system discharge tunnel/canal. The area it travels through under the turbine building houses no SR components, so a pressure boundary of the piping does not represent a spatial interaction concern. As such, only the SW discharge flow itself is within the scope of license renewal. Peripheral piping and components such as those identified serve no intended function and are not within the scope of license renewal

Based on its review, the staff found the applicant's response acceptable, because the NSR lines under the turbine building do not represent a spatial interaction concern. Therefore, the staff's concerns described in RAI 2.3.3.7-4a and 4b are resolved.

In RAIs 2.3.3.7-5a and 5b, the staff stated that license renewal drawing D-02034-LR, sheet 1, locations E-2, and E-1, depict two manholes that are not within the scope of license renewal. License renewal drawing D-20034-LR, sheet 2, locations D-8, and E-7, depict two manholes that appear to be within the scope of license renewal. Therefore, the staff requested that the applicant clarify if these manholes are within the scope of license renewal and if not, explain why these manholes are not within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the subject piping/components are attached to the 36-inch SW discharge line. The NSR SW discharge line was within the scope of license renewal for providing a discharge flow path from SR components in the reactor building to the CW system discharge tunnel/canal. The area it travels through under the turbine building houses no SR components, so a pressure boundary of the piping does not represent a spatial interaction concern. As such, only the SW discharge flow itself is within the scope of license renewal. Peripheral piping and components such as those identified serve no intended function and are not within the scope of license renewal.

Based on its review, the staff found the applicant's response acceptable because the NSR lines under the turbine building do not represent a spatial interaction concern. Therefore, the staff's concerns described in RAIs 2.3.3.7-5a and 5b are resolved.

In RAIs 2.3.3.7-6a and 6b, the staff stated that license renewal drawing D-02034-LR, sheet 1, location E-2, depict three sections of pipe which include valves 2-SW-V443 (2-SW-296-30-R-1) and 2-SW-299 (2-SW-266-1-R-2) and pipe line number (2-SW-22-30-R-1) that are not within the scope of license renewal. Similarly, license renewal drawing D-20034-LR, sheet 2, location E-7, depict three sections of pipe which include valves 2-SW-V443 (1-SW-296-30-R-1) and 1-SW-299 (1-SW-228-1-R-2) and pipe line number (1-SW-22-30-R-1) that are not within the scope of license renewal. Therefore, the staff requested that the applicant explain why these sections of pipe and valves are not within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the subject piping/components are attached to the 36-inch SW discharge line. The NSR SW discharge line is within the scope of license renewal for providing a discharge flow path from SR components in the reactor building to the CW system discharge tunnel/canal. The area it travels through under the turbine building houses no SR components, so a pressure boundary of the piping does not represent a spatial interaction concern. As such, only the SW discharge flow itself is within scope. Peripheral piping and components such as those identified above serve no intended function and are not within the scope of license renewal.

Based on its review, the staff found the applicant's response acceptable because the NSR lines under the turbine building do not represent a spatial interaction concern. Therefore, the staff's concerns described in RAIs 2.3.3.7-6a and 6b are resolved.

In RAIs 2.3.3.7-7a and 7b, the staff stated that license renewal drawing D-02041-LR, sheet 2, locations B-3 and B-6, depict three lines each from the nuclear header SW pumps. Similarly license renewal drawing D-20041-LR, sheet 2, locations B-3 and B-6, depict three lines each from the nuclear header SW pumps with continuations on drawing F-40024. Drawing F-40024 was not provided with the LRA. Therefore, the staff requested that the applicant provide additional information as to where the LRA boundary is located for these sections of pipe.

In its response, by letter dated May 4, 2005, the applicant stated that the subject lines are the seal leakoff and lube oil cooler discharge lines on the nuclear SW pumps. They are in scope to provide a discharge flow path in support of the operation of the pumps. All three lines discharge into an open hub drain, which drains directly down into the pump intake bay. Failure of the hub drain itself and the short run of pipe back to the pump bay could not obstruct the flow path of these lines, nor otherwise present a liability to the pump or nearby SR equipment. As such, the hub drain and piping depicted on F-4024 perform no intended function and are not within the scope of license renewal.

Based on its review, the staff found the applicant's response acceptable because all six lines discharge into an open hub drain, which drains directly down into the pump intake bay. Failure of the hub drain itself and the short run of pipe back to the pump bay could not obstruct the flow path of these lines, nor otherwise present a liability to the pump or nearby SR equipment. Therefore, the staff's concerns described in RAIs 2.3.3.7-7a and 7b are resolved.

In RAI 2.3.3.7-8a and 8b, license renewal drawing D-02041-LR, sheet 2, location F-7, has an LRA flag in the middle of a section of pipe which is continued on D-2041-3 and D-2034. Similarly, license renewal drawing D-20041-LR, sheet 2, location F-2, has an LRA flag in the middle of a section of pipe which is continued on D-20034 and D-20041-3. Therefore, the staff requested that the applicant explain why the LRA boundary occurs in the middle of these sections of pipe.

In its response, by letter dated May 4, 2005, the applicant stated that the subject lines are the SW supply to NSR cooling loads in the turbine building, as well as a fill line to the CW system. The SR portion of the line ends at the 2-SW-V3 and 1-SW-V3 valves. The highlighted portions of the license renewal drawings indicate the extent of the piping included in the seismic evaluation. The license renewal flag on line 2-SW-100-30-R-1 indicates the terminus of the seismic evaluation.

Based on its review, the staff found the applicant's response acceptable because the SR portion of the line ends at the 2-SW-V3 and 1-SW-V3 valves, and a segment of piping past these points has been included for seismic support. The boundary flag represents the terminus of the seismic evaluation. Therefore, the staff's concerns described in RAIs 2.3.3.7-8a and 8b are resolved.

In RAIs 2.3.3.7-9a and 9b, the staff stated that license renewal drawing D-02537-LR, sheet 2, location B-2, has an LRA flag in the middle of a section of pipe which is continued on D-2544. Similarly, license renewal drawing D-25037-LR, sheet 2, location B-2, has an LRA flag in the middle of a section of pipe which is continued on D-25043, sheet 1B. Therefore, the staff requested that the applicant explain why the LRA boundary occurs in the middle of these sections of pipe.

In its response, by letter dated May 4, 2005, the applicant stated that line 2-G16-1178-1-160 and line 1-G16-1177-1-160 are NSR lines that were brought within the scope of license renewal because they are required to protect the SR/NSR boundary at valve 2-E11-F073 and 1-E11-F073. The highlighted portions of the license renewal drawings indicate the extent of the

piping included in the seismic evaluation. The license renewal flag on lines 2-G16-1178-1-160 and
1-G16-1178-1-160 indicates the terminus of the seismic evaluation.

Based on its review, the staff found the applicant's response acceptable because the subject lines are within the scope of license renewal and are required to protect the SR/NSR boundary at valve 2-E11-F073 and 1-E11-F073. The highlighted portions of the license renewal drawings indicate the extent of the piping included in the seismic evaluation. Therefore, the staff's concerns described in RAIs 2.3.3.7-9a and 9b are resolved.

2.3.3.7.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the SW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.8 Reactor Building Closed Cooling Water System

2.3.3.8.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.8, the applicant described the reactor building closed cooling water (RBCCW) system. The RBCCW system removes heat from the reactor auxiliary systems and their related accessories during normal operation. The system also provides an additional barrier between contaminated systems and the SW discharged to the environment. Those portions of the system that are within the scope of license renewal are located in the drywell, reactor building, and control building. The RBCCW system provides cooling for the non-regenerative heat exchangers, reactor coolant recirculation system pump and motor coolers, sump and equipment drain tank coolers, sample coolers, cleanup recirculation pump coolers, cleanup pre-coat pump coolers, fuel pool heat exchangers, drywell coolers, CRD supply pump coolers, and penetration cooling system. The RBCCW system pumps, heat exchangers, and equipment required for normal system heat removal are designed to Class II requirements. RBCCW system instrumentation and control circuits activate protective actions following postulated accidents and transients, and system indicating circuits support post-accident monitoring functions, such as containment isolation valve position.

The RBCCW system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the RBCCW system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the RBCCW system performs functions that support EQ. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-7, the applicant identified the following RBCCW system and penetration cooling system component types that are within the scope of license renewal and subject to an AMR:

- piping (pipe, fittings, and flanges)
- piping (piping specialties)
- valves (check, hand, control, relief, solenoid, and containment isolation) (body and bonnet)
- pump (casing)
- tank (shell)
- flow orifice (body)
- closed-cycle cooling water system (strainers)
- closed-cycle cooling water system (heat excahangers)
- closed-cycle cooling water system (piping specialties)
- valves (including check valves and containment isolation) (body and bonnet)
- pressure regulators (body and bonnet)

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8 and UFSAR Section 9.2.2 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.8 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.8-1, dated April 8, 2005, the staff stated that sheet 2 of license renewal boundary drawings D-25038-LR and D-02538-LR (quadrants C4 and D4) show the in-scope boundary terminating in the middle of non-isolable portions of lines 1(2)-RCC-6-6-154 and 1(2)-RCC-54-2-154. Therefore, the staff requested that the applicant discuss the basis for terminating the in-scope portion of this piping at these locations and provide additional information describing the as-built plant locations that these scope boundaries represent.

In its response, by letter dated May 4, 2005, the applicant stated that the piping described in RAI 2.3.3.8-1 (1(2)-RCC-6-6-154 and 1(2)-RCC-54-2-154) performs no SR function and that portions of this piping are within the scope of license renewal for potential spatial interaction. The applicant stated that the scoping boundary described in boundary drawings D-25038-LR and D-02538-LR (quadrants C-4 and D-4) represents the point at which RBCCW enters an area in the reactor building that houses no SR components and is sufficiently isolated/protected from other parts of the reactor building to preclude adverse spatial interactions with SR components elsewhere in the building.

Based on its review, the staff found the applicant's response acceptable because the applicant has sufficiently clarified that the in-scope boundaries for portions of lines 1(2)-RCC-6-6-154 and 1(2)-RCC-54-2-154 described in boundary drawings D-25038-LR and D-02538-LR (quadrants C-4 and D-4) are consistent with plant as-built configurations and that the failure of the out-of-scope piping would not impact the intended functions of SR components. Therefore, the staff's concern described in RAI 2.3.3.3-1 is resolved.

In RAI 2.3.3.8-2, dated April 8, 2005, the staff stated that license renewal boundary drawing D-25038-LR sheet 2 (quadrants E1 and E2) identifies a portion of the RBCCW supply piping (1-RCC-57-1½ -154) to cleanup recirculation pump cooler 1B and adjacent valve V304 as within the scope of license renewal. This is inconsistent with the RBCCW supply piping and valve combinations for the remaining Unit 1 cleanup recirculation pump cooler 1A and the Unit 2 cleanup recirculation pump coolers 1A and 1B (sheet 2 of D-02538-LR), which are shown as out of scope for license renewal. Therefore, the staff requested that the applicant discuss the basis for terminating the in-scope portion of this piping at these locations and provide additional information describing the as-built plant locations that the in-scope boundaries represent.

In its response, by letter dated May 4, 2005, the applicant stated that the portion of the RBCCW supply piping (1-RCC-57-12 -154) to cleanup recirculation pump cooler 1B and adjacent valve V304 shown as in-scope for license renewal on boundary drawing D-25038-LR sheet 2 (quadrants E-1 and E-2) is a drawing error. The applicant stated that this piping does not perform an SR function and is located in an area in the reactor building that houses no SR components and is sufficiently isolated/protected from other parts of the reactor building to preclude adverse spatial interactions with SR components elsewhere in the building. The applicant stated that boundary drawing D-25038-LR, sheet 2 will be revised to show that this piping is not within the scope of license renewal. Based on its review, the staff found the applicant's response acceptable. Therefore, the staff's concern described in RAI 2.3.3.8-2 resolved.

2.3.3.8.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the RBCCW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the RBCCW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.9 Turbine Building Closed Cooling Water System

2.3.3.9.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.9, the applicant described the turbine building closed cooling water (TBCCW) system. The TBCCW system is a closed loop system, which removes heat from the following secondary plant equipment and turbine-generator accessories: (1) turbine-generator lube oil coolers, (2) turbine-generator electro-hydraulic control system coolers, (3) generator stator and rectifier coolers, (4) generator bus duct heat exchangers, (5) Alterex exciter coolers, (6) generator hydrogen coolers, (7) air compressors and air aftercoolers, (8) turbine building sample coolers, (9) condenser mechanical vacuum pump coolers, (10) reactor feed pump turbine oil coolers, (11) recirculation pump motor-generator set oil coolers, (12) heater drain pump jacket and motor thrust bearings, (13) condensate pump motor thrust bearings, (14) condensate booster pump oil coolers. Each unit is provided with a TBCCW system consisting of two pumps, two heat exchangers and integrated piping. The systems utilize a common head tank. In addition, the Unit 2 TBCCW system is equipped with a chemical feed tank and a spare pump and heat exchanger. The spare pump and/or heat exchanger may be lined up to either unit’s TBCCW system but not both. The TBCCW pumps that are arranged in parallel take suction from a common header and discharge to the heat exchangers.

The failure of NSR SSCs in the TBCCW system could potentially prevent the satisfactory accomplishment of an SR function.

The TBCCW system components that are subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 and UFSAR Section 9.2.7 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.9.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the TBCCW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the TBCCW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.10 Diesel Generator System

2.3.3.10.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.10, the applicant described the DG system. The DG system provides emergency alternating current (AC) power to the onsite electrical distribution system of each unit. The DG system contains four emergency diesel generator sets and is used to ensure that a supply of electrical power is available for the operation of SR equipment in the event of loss of offsite power. Electrical equipment and controls that are required to start and load the diesel, or prevent it from operating are classified SR. Diesel capacity is such that any three of the four diesels provided can supply all required loads for the safe shutdown of one unit and a design-basis accident on the other unit without offsite power. During a SBO event, diesel capacity is such that one operational diesel can supply the required loads for safe shutdown of the non-blacked-out unit and the required SBO coping loads in the blacked-out unit. The DG system provides the AC power required by the Class 1E distribution system to provide power for emergency systems and engineered safety features during and following the shutdown of the reactor when the preferred power supply is not available. The system starts automatically on loss of voltage to its associated buses, an ESF actuation signal on either unit, a loss of offsite power, or a unit trip of either unit.

Support systems necessary to ensure proper operation of the DGs are (1) diesel fuel oil system, (2) diesel lube oil system, (3) diesel jacket water system, (4) DG SW system, (5) DG starting air system, and (6) DG intake/exhaust system. The diesel fuel oil system stores and distributes fuel oil for use by the DGs. The diesel lube oil system is a closed loop system that lubricates various DG components and rejects heat to the lube oil cooling subsystem. The diesel jacket water system is a closed loop system that removes most of the heat generated by the DG during operation by cooling the engine components and DG lubricating oil. The DG SW system contains redundant SW supply lines to remove heat from each DG jacket water cooler; if the normal supply is not available, the alternate supply line valve will open and the normal supply valve will close. The DG starting air system provides compressed air to the diesel engine cylinders for starting the emergency DGs and supplies air to the instrumentation and controls. The DG intake/exhaust system provides combustion air to each DG and removes exhaust gases and potentially explosive fumes from each DG.

The DG system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the DG system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the DG system performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides filtration
- provides flow restriction (throttle)

- provides structural support/seismic integrity
- provides heat transfer

In LRA Table 2.3.3-8, the applicant identified the following DG system component types that are within the scope of license renewal and subject to an AMR:

- valves, connected pipe, tubing and fittings
- piping (aboveground pipe and fittings)
- piping (underground pipe and fittings)
- valves (body and bonnet)
- pump (casing)
- tank (internal/external surface)
- immersion element (pressure-retaining housing)
- strainer (body)
- tanks (day and drip)
- filters (shell)
- valves, connected pipe, tubing and fittings
- heaters an thermowells (housing)
- filter (shell)
- pump (casing)
- gauge glass
- heat exchanger (tubes)
- heat exchanger (shell)
- heat exchanger (tube sheet and channel head)
- strainer (casing)
- strainer (screen)
- heat exchanger (shell)
- heat exchanger (channel)
- heat exchanger (channel head and access cover)
- heat exchanger (tubesheet)
- heat exchanger (tubes)
- piping (pipe, fittings, and flanges)
- valves (check, hand, control, relief, solenoid, and containment isolation) (body and bonnet)
- closed-cycle cooling water system (piping specialties)
- diesel engine cooling water subsystem (pipe and fittings)
- diesel engine cooling water subsystem (tanks and vessels)
- diesel engine cooling water subsystem (heat exchangers)
- diesel engine cooling water subsystem (pumps)
- diesel engine cooling water subsystem (piping specialties)
- piping (piping and fittings)
- piping (piping specialties)
- valves (body and bonnet)
- pipe and fittings
- valves (hand and check)
- drain trap
- air accumulator vessel
- filter (shell)
- strainer (shell)

- strainer (basket)
- piping and fittings
- filter
- muffler (intake silencer)
- turbo charger (inlet-housing)
- valve (body), connected piping, tubing and fittings
- turbo charger (inlet-bellows)
- filter (media)
- piping and fittings
- muffler (exhaust)
- fans (housing)
- oil separator (housing)
- valve (body), connected pipe and fittings
- turbo charger (exhaust-housing)
- turbo charger (exhaust-bellows)

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 and UFSAR Sections 8.3.1.1.6 through 8.3.1.1.6.2.14 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.10 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.10-1, the staff stated that the DG system has several auxiliary support systems, including the diesel fuel oil system, that must function in order to perform its SR functions. There are two sections of piping associated with fuel oil transfer pump 2A shown on drawing D-02268-LR, sheet 1B, at locations B-3 and B-4, that are shown as being out of scope for license renewal. This is not consistent with the fuel transfer pump 1A shown on drawing D-02268-LR, sheet 1A, at locations B-3 and B-4, which shows the same piping sections as being within the scope of license renewal. Therefore, the staff requested that the applicant provide additional clarification or justification to support the determination that it is acceptable to not include these sections of piping as within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the two sections of piping components associated with fuel oil transfer pump 2A shown on drawing D-02268-LR, sheet 1B, at locations B-3 and B-4, are within the DG system license renewal scoping boundary and subject to an AMR. Therefore, the staff found the applicant's response acceptable and the staff's concern described in RAI 2.3.3.10-1 is resolved.

In RAI 2.3.3.10-2, the staff stated that the DG system has several auxiliary support systems, including the diesel fuel oil system, that must function in order to perform its SR functions. There are several blind flanges and fittings for the DG fuel oil storage tanks listed below that are not consistently treated as being either within the scope or out of the scope of license renewal.

- DG No. 1 fuel oil day tank the 2-inch blind flange on drawing D-02268-LR, sheet 1A, at location F-6, is shown as being out of scope.
- DG No. 1 four day storage tank: the 6-inch blind flange, 24-inch man hole, and 2-inch blind flange on drawing D-02268-LR, sheet 1A, at locations C-4 and B-5, are shown as being in scope.
- DG No. 1 fuel oil transfer pump 1B on drawing D-02268-LR, sheet 1A, at location C-2, has a discharge pressure tap pipe plug down stream of PI-1242-6 that is shown as being out of scope. This is inconsistent with fuel oil transfer pump 1A that has a similar pipe plug downstream of PI-1241-6 that is shown as being in scope.
- DG No. 2 fuel oil day tank: the 2-inch blind flange on drawing D-02268-LR, sheet 1B at location F-6 is shown as being out of scope.
- DG No. 2 four day storage tank: the 6-inch blind flange on drawing D-02268-LR, sheet 1B, at location C-4, is shown as being out of scope.
- DG No. 3 fuel oil day tank: the 2-inch blind flange on drawing D-02269-LR, sheet 2A, at location F-6, is shown as being out of scope.
- DG No. 3 four day storage tank: the 6-inch blind flange, 24-inch man hole, and 2-inch blind flange on drawing D-02269-LR, sheet 2A, at locations C-4 and B-5, are shown as being in scope.
- The diesel seven day storage tank: shown on drawing D-02269-LR, sheet 2A at location B-7 shows a man way, an instrument line flanged access, and a tank fill line that are shown as being out of scope.
- DG No. 4 fuel oil day tank: the 2-inch blind flange, 2-inch blind flange and 6-inch blind flange on drawing D-02269-LR, sheet 2B at locations F-6, B-5, and C-4 are shown as being out of scope.

Therefore, the staff requested that the applicant provide additional clarification or justification to support the determination that it is acceptable to not include the blind flanges and fittings listed above as within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the blind flanges and fittings identified are either piece-parts or miscellaneous appendages of in-scope components and are, therefore, conservatively assumed to be within the diesel fuel oil system license renewal scoping boundary and subject to an AMR. The staff found the applicant's response acceptable, therefore, the staff's concern described in RAI 2.3.3.10-2 is resolved.

In RAI 2.3.3.10-3, the staff stated that the DG system has several auxiliary support systems, including the diesel lube oil system, that must function in order to perform its SR functions. There are several instrument lines, fittings, and piping segments for the diesel generator lube oil systems listed below that are not consistently treated as being either in scope or out of scope for license renewal.

- DG No. 1 engine control panel pressure gage PI-6520 piping on drawing D-02270-LR, sheet 1A, at location F-7, is shown as being out of scope. This is inconsistent with similar pressure gage piping for DG No. 2 on drawing D-02270-LR, sheet 1B, at the same location that is shown as being in scope.
- DG No. 2 sensing line for TI-6542-2 on drawing D-02270-LR, sheet 1B, at location C-6, is shown as being in scope. This is inconsistent with similar sensing lines for DG No. 1 on drawing D-02270-LR, sheet 1A, at the same location that is shown as out of scope. This same sensing line for DG No. 3, TI-6542-3; and DG No. 4, TI-6542-4, is also shown as being out of scope.
- DG No. 1 level switch LS-6562-1 piping on drawing D-02270-LR, sheet 1A, at location E-6 is shown as being out of scope. This is inconsistent with similar level switch piping for DG No. 2 on drawing D-02270-LR, sheet 1B, at the same location that is shown as being in scope.
- DG No. 2 pipe cap downstream of SS-6577-2-10 on drawing D-02270-LR, sheet 1B, at location E-5, is shown as being out of scope. This is inconsistent with similar pipe caps for DG No. 1 on drawing D-02270-LR, sheet 1A, at the same location that is shown as being in scope. This same pipe cap is also shown as being in scope for DG No. 3 and DG No. 4.
- For DG Nos. 1, 3, and 4, there is a 3-inch diameter piping segment on drawings 0-02270-LR, sheet 1A, at location E-4; D-02271-LR, sheet 2A, at location B-4; and D-02271-LR at location B-4 shown as being out of scope. This is inconsistent with DG No. 2 that shows the same 3-inch diameter piping segment at the same location as being in scope.

Therefore, the staff requested that the applicant provide additional clarification or justification to support the determination that it is acceptable to not include the instrument lines, fittings, and piping segments listed above as within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the instrument lines, fittings, and piping segments for the DG lube oil systems listed in RAI 2.3.3.10-3 are within the DG system license renewal scoping boundary and are therefore subject to an AMR. The staff found the applicant’s response acceptable; therefore, the staff's concerns identified in RAI 2.3.3.10-3 are resolved.

In RAI 2.3.3.10-4, the staff stated that the DG system has several auxiliary support systems, including the diesel SW system, that must function in order to perform its SR functions. The license renewal documentation shows inconsistencies in how the vent piping and pipe caps are shown for this system. For DG No. 1, there is a vent pipe and pipe caps on drawing D-02274-LR, sheet 1, at location E-3, that are shown as out of the scope of license renewal. There is also a pipe cap for DG No. 2 on drawing D-02274-LR, sheet 1, at location E-6, that is shown as out of scope. The same vent piping and pipe caps for DG No. 3 and DG No. 4 on drawing D-02274-LR, sheet 2, at the same locations are shown in scope. Therefore, the staff requested that the applicant provide additional clarification or justification for not including these sections of piping and pipe caps as within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the vent piping and pipe caps identified in RAI 2.3.3.10-4 are miscellaneous appendages of in-scope components and are, therefore, conservatively assumed to be within diesel SW system license renewal scoping boundary and subject to an AMR. The staff found the applicant's response acceptable; therefore, the staff's concern described in RAI 2.3.3.10-4 is resolved.

In RAI 2.3.3.10-5, the staff stated that the DG system has several auxiliary support systems that must function in order to perform its SR functions including the diesel exhaust and crankcase vacuum blower system. The crankcase vacuum blower discharge lines shown on drawings D-02267-LR, sheets 1 and 2, at locations C-3 and C-6, are not shown as within the scope of license renewal. The crankcase vacuum blower system ensures potentially dangerous crankcase vapors are exhausted to the atmosphere. It is not clear that the crankcase vacuum blower system could perform its intended function if the discharge lines are damaged, pinched off, fail, or are otherwise restricted. Therefore, the staff requested that the applicant provide additional clarification or justification to support the determination that it is acceptable to not include the crankcase vacuum blower discharge lines as within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the piping down stream of the four diesel crank case vacuum blowers is classified in the plant design records as NSR and is not credited as being required for any of the 10 CFR 54.4 (a)(3) events. The applicant stated that the restriction of crank case ventilation in the vacuum blower discharge lines shown on drawings D-02267-LR, sheets 1 and 2, is a hypothetical event outside of the CLB, therefore, not addressed as a scoping consideration under 10 CFR 54.4. The applicant also stated that potential age-related degradation of the piping could allow the leakage of crank case fumes into the diesel building but would not impact the safety function of the DGs.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.10-5 acceptable, because the crank case vacuum blower is a non-safety related component and age related degradation would not impact the safety function of the DG. Thus, it does not perform an intended function within the meaning of the 10 CFR 54.4(a) criteria. Therefore, the staff's concern described in RAI 2.3.3.10-5 is resolved.

2.3.3.10.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the DG system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the DG system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Heat Tracing System

2.3.3.11.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.11, the applicant described the heat tracing system. The original purpose of the freeze protection and heat tracing system was to provide a source of heat to prevent certain system piping from freezing and/or to maintain proper process system fluid temperatures. The system is no longer used for these purposes and its name has been changed to the heat tracing system. However, a steam line from the system supporting CAC system nitrogen vaporization is located in the vicinity of SR equipment in the AOG building. Therefore, it was concluded that the system contains NSR components (steam piping and valve) that have the potential to cause an adverse physical interaction with SR equipment. These components have been included within the scope of license renewal as a result of the 10 CFR 54.4(a)(2) review.

The failure of NSR SSCs in the heat tracing system could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-9, the applicant identified the following heat tracing system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (steam drains)
- valves (check, control, hand, motor operated, safety valves) (body and bonnet)

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11 and UFSAR Sections 10.4.8 and 3A-22 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.11.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the heat tracing system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the heat tracing system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 Instrument Air System

2.3.3.12.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.12, the applicant described the instrument air (IA) system. The IA system provides instrument-quality air to pneumatically operated instruments and controls throughout the plant. Instrument air consists of interruptible instrument air and non-interruptible instrument air. The interruptible instrument air system provides operating air to less vital pneumatic instruments and controls and is not essential to safe plant shutdown. The non-interruptible instrument air system is designed with the capability of supplying instrument air requirements in the reactor building (RB) required for plant safety during normal operation. The nitrogen backup system (also designated reactor non-interruptible air (RNA)) provides an independent, SR pneumatic source to selected SR loads in the event of either a LOCA or the loss of the normal pneumatic supply. The CAD system provides a backup to the instrument air header in the AOG building upon loss of instrument air for the CAD subsystem. Components in the IA system automatically actuate and monitor backup nitrogen supplies when required.

The IA system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the IA system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the IA system performs functions that support fire protection, EQ, and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.3.12, the applicant identified the following IA system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)
- air receiver (shell and access cover)
- pressure regulators (body and bonnet)
- filter (shell and access cover)

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 and UFSAR Section 9.3.1 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.12 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.12-1, the staff stated that the IA system receivers 1A, 1B, 2A, and 2B are within the scope of license renewal and provide a pressure-retaining boundary function; however, none of the air receiver discharge lines that allow the system to provide IA to components are identified as being within the scope of license renewal on the following drawings:

- D-70029-LR, sheet 2B, at location E-7 (line 221-2-170)
- D-72006-LR, sheet 4, at location B-1 (line 201-2-170, 206-2-170, 215-2-170, 220-2-170)
- D-07029-LR, sheet 2A, at location F-1 (line 201-2-170, 251-2-170, 203-2-170)
- D-07029-LR, sheet 2B, at location E-7 (line 221-2-170)

Therefore, the staff requested that the applicant provide information and justify its determination to exclude the identified lines from the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated:

> The referenced Instrument Air (IA) Receivers 1A, 1B, 2A, 2B are located in the Unit 1 and Unit 2 Reactor Buildings and quality classified as non-safety related. These air receivers are discussed in UFSAR Section 3.5.1.1. The IA System safety evaluation is described in UFSAR Section 9.3.1.2.3. BNP-LR-007, "License Renewal Scoping Calculation For Criteria 10 CFR 54.4(a)(2) Nonsafety Affecting Safety-Related Equipment," Revision 2, page 20 states:
>
>> Missiles may be generated by failure of compressed air tanks located within buildings/structures. The Reactor Building air receivers are located in the vicinity of safety related equipment, hence these receivers are included in the scope of License Renewal.
>
> Thus, the referenced IA Receivers 1A, 1B, 2A, and 2B are in the scope of License Renewal for a spatial interaction, not a functional relationship. The plant does not rely on the instrument air in these receivers to accomplish the function of a safety related or a regulated event component. Failure of the identified lines would not prevent the IA System from performing its required safety functions.

Based on its review, the staff found the applicant's response acceptable because failure of the air receiver discharge lines will not result in failure of the intended safety functions of the systems. Therefore, the staff's concerns described in RAI 2.3.3.12-1 are resolved.

In RAI 2.3.3.12-2, the staff stated that license renewal boundary drawings D-70077-LR, sheet 3A, and D-07077-LR, sheet 3A, both identify the valve B32-F020, at location B-1, as being within the scope of license renewal; however, the lines connecting valve B32-F020 to the IA header are not shown as being within the scope of license renewal. Therefore, the staff requested that the applicant provide information to justify its determination to exclude the piping that connects the IA header to valve B32-F020.

In its response, by letter dated May 4, 2005, the applicant stated:

> Valve B32-F020 is a recirculation sample line isolation valve, which is a safety related valve in System 2020. Per design basis document, DBD-002, "Reactor Coolant Recirculation System," Revision 9, Section 4.4.3, this valve is an air-operated globe valve, which receives automatic closure signals. This valve has alternating current solenoid pilots which de-energize to vent air from the diaphragm to allow valve closure by spring action using de-energize-to-close "fail-safe" logic.
>
> The IA System is not required for valve B32-F020 to perform its safety related function. Failure of the IA piping would not cause loss of function of valve B32-F020. This valve fails to the safe position without IA supply. Non-safety related IA lines connecting valve B32-F020 to the IA header are correctly shown as not being within scope.

Based on its review, the staff found the applicant's response acceptable because valve B32-F020 fails to the safe position without IA supply. Failure of the IA piping would not cause loss of function of valve B32-F020. Therefore, the staff's concern described in RAI 2.3.3.12-2 is resolved.

2.3.3.12.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the IA system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the IA system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.13 Service Air System

2.3.3.13.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.13, the applicant described the service air (SA) system. The SA system provides compressed air from the service air header to selected auxiliary equipment and to service outlets throughout the plant. A manual cross-tie isolation valve and necessary piping connect the SA headers between units for improved reliability. The SA system has no SR functions other than containment isolation in any mode of operation as the system does not supply air to any component requiring air to perform an SR function. The containment isolation function is performed by a segment of piping that has been cut and capped inside and outside the containment wall. In addition, those portions of the system in close proximity to, and which may adversely interact with, SR equipment are designed to limited seismic qualification requirements and are within the scope of license renewal. The supports for the piping prevent the occurrence of adverse spatial interactions.

The SA system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the SA system could potentially prevent the satisfactory accomplishment of an SR function. The SA system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13 and UFSAR Section 9.3.1 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.13.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the SA system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SA system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.14 Pneumatic Nitrogen System

2.3.3.14.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.14, the applicant described the pneumatic nitrogen system (PNS). The PNS provides gaseous nitrogen to pneumatically operated components in the drywell to prevent an increase in drywell atmosphere oxygen concentration due to releases of air from valve operation and leakage. The nitrogen for PNS is provided from two cryogenic tanks, one for each unit, located in the yard area southeast of the Unit 2 reactor building. This system may be used as backup to service and instrument air. The PNS, which is the normal pneumatic supply to the drywell during plant operation, may be isolated at low power levels (including unit shutdown) to allow personnel access to the drywell. The PNS provides gaseous nitrogen needed for operation of the instrumentation and pneumatic controls in the drywell only during normal plant operation;

it has no SR function. Those portions of the system in close proximity to, and which may interact with, SR equipment are designed to limited seismic qualification requirements to prevent undesirable interactions with SR equipment.

The failure of NSR SSCs in the PNS could potentially prevent the satisfactory accomplishment of an SR function. The intended function, within the scope of license renewal, is to provide structural support/seismic integrity.

In LRA Table 2.3.3-11, the applicant identified the following PNS component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)
- filter (shell and access cover)

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14 and UFSAR Section 9.3.1 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In reviewing LRA Section 2.3.3.14, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.14-1, the staff stated that license renewal drawing D-02494-LR, sheet 1, location F-2, has a section of piping with a continuation to D-07077-3A, location F-6, that is not within the scope of license renewal. Note that the continuation could not be found on D-07077-3A, location F-6. Therefore, the staff requested that the applicant provide additional justification as to why this section of pipe is not within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated:

> Pneumatic Nitrogen System (PNS) Line 2-PNS-001-3/4-167 is a non-safety related line that was brought within the scope of License Renewal because it is required to protect the safety related/non-safety related boundary at valve 2-RNA-SV-5262.

The License Renewal boundary flag on Drawing D-02494-LR, Sheet 1, should have been placed upstream of the reducer (i.e., upstream of 2-RNA-V255) to match the boundary flag location on Drawing D-07077-LR, Sheet 3A.

Line 2-PNS-3-1/2-154 is an NSR line that is not within the scope of License Renewal because it is upstream of the corrected License Renewal boundary flag and its failure does not affect the seismic qualification of the safety related/non-safety related boundary at valve 2-RNA-SV-5262.

Based on its review, the staff found the applicant's response acceptable. Line 2-PNS-3-1/2-154 is an NSR line that is not within the scope of license renewal because it is upstream of the corrected license renewal boundary flag and its failure does not affect the seismic qualification of the SR/NSR boundary at valve 2-RNA-SV-5262. Therefore, the staff's concern described in RAI 2.3.3.14-1 is resolved.

In RAI 2.3.3.14-2, the staff stated that license renewal drawing D-02494-LR, sheet 1, location F-3, depicts the piping, and isolation and bypass valves to 2-PNS-FLT-100 to be within the scope of license renewal. A similar piping arrangement for 2-PNS-FLT-101 (see drawing D-07077, sheet 3B, location C-3) indicates 2-PNS-FLT-101 is not within the scope of license renewal. Therefore, the staff requested that the applicant provide information as to whether 2-PNS-FLT-101 and associated piping and valves are within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that line 2-PNS-002-3/4-167 is an NSR line that was brought within the scope of license renewal because it is required to protect the SR/NSR boundary at valve 2-RNA-SV-5261. The license renewal boundary flag on drawing D-02494-LR, sheet 1, should have been placed upstream of the reducer (i.e., upstream of 2-RNA-V256) to match the boundary flag location on drawing D-07077-LR, sheet 3B. Filter 2-PNS-FLT-101 and the associated valves 2-PNS-V5006, 2-PNS-V5007, and 2 PNS V5008 are beyond the corrected license renewal boundary flag and are consequently not required to be within the scope of license renewal.

Based on its review, the staff found the applicant's response acceptable because filter 2-PNS-FLT-101 and the associated valves 2-PNS-V5006, 2-PNS-V5007, and 2 PNS V5008 are beyond the corrected license renewal boundary flag and are consequently not required to be within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.14-2 is resolved.

In RAI 2.3.3.14-3, the staff stated that license renewal drawing D-07077-LR, sheet 3A, location C-6, shows a license renewal boundary designator between valves V255 and 2-PNS-V5004. Drawing D-02494-LR, sheet 1, location F-3, indicates the piping between V255 and V5004 as within scope and piping and valves from PSL 5843A2, 2-PNS-V12, and 2-PNS-V8 to V255, including 2-PNS-V5004 are within the scope of license renewal. The piping between 2-PNS-V12, 2-PNS-V8, 2-PNS-V5004 is shown not shaded on D07077 sheet 3A. A similar situation exists with drawing D-02494-LR, sheet 1, and D-07077-LR, sheet 3B, from V256 through 2-PNS-V11 and 2-PNS-V7. Therefore, the staff requested that the applicant explain these apparent license renewal boundary discrepancies between drawing D-02494-LR, sheet 1, and drawing D-07077-LR, sheet 3A and B, and to provide justification for why the piping between 2-PNS-V12, 2-PNS-V8, 2-PNS-V5004 is not shown as in scope on drawing D07077 sheet 3A.

In its response, by letter dated May 4, 2005, the applicant stated that the license renewal boundary flags on drawings D-07077, sheet 3A and sheet 3B, are associated with the piping upstream of the SR/NSR boundaries for valves 2-RNA-SV-5262 and 2-RNA-SV-5261, respectively. As discussed in the responses to RAI 2.3.3.14-1 and RAI 2.3.3.14-2, the license renewal boundary flags shown on drawing D-02494, sheet 1 are incorrect. Placing the license renewal boundary flags in the correct location will remove the discrepancies among the three referenced drawings: D-02494-LR, sheet 1; D 07077 LR, sheet 3A; and D-07077-LR, sheet 3B.

Based on its review, the staff found the applicant's response acceptable because the license renewal boundary flags shown on drawing D-02494, sheet 1 are incorrect. Placing the license renewal boundary flags in the correct location will remove the discrepancies among the three referenced drawings: D-02494-LR, sheet 1; D 07077 LR, sheet 3A; and D-07077-LR, sheet 3B. Therefore, the staff's concerns described in RAI 2.3.3.14-3 are resolved.

2.3.3.14.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the PNS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the PNS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Fire Protection System

2.3.3.15.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.15, the applicant described the fire protection system. The Fire Protection Program consists of design features, equipment, personnel, and procedures that combine to provide multi-tiered safeguards against a fire that could impact the health and safety of the public. Within the Fire Protection Program, the fire protection system uses the philosophy of defense in depth. The objectives of the fire protection system are to (1) rapidly detect, control, and promptly extinguish those fires that do occur; (2) provide protection for SSCs important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant; and (3) deliver extinguishing agents to areas of the plant through manually and automatically actuated devices. Both water-based and gaseous fire suppression systems are used. The gaseous systems are the CO_2 and halon systems. Water suppression from duplicate sources, powered by independent means is available from the water-based system in plain water or with foam both automatically and manually through sprinkler, deluge, and hydrant/hose stations. Portable extinguishers are also available to provide an additional level of protection. The fire protection system includes physical barriers (doors, walls, seals, etc.) to inhibit the spread of fire and detection equipment for automatic suppression in selected areas. Carbon dioxide fire suppression is used where the consequences of water damage are severe and the hazard can be mitigated readily by oxygen exclusion. Halon systems provide fire protection for several areas and buildings. Design concepts used in the Fire

Protection Program provide assurance that a fire will not cause the complete loss of function of SR systems, even though limited loss of redundancy within one system may occur.

The fire protection system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the fire protection system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the fire protection system performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)
- provides heat transfer
- provides adequate flow in a properly-distributed spray pattern

In LRA Table 2.3.3-12, the applicant identified the following fire protection system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (includes carbon steel fire water tank)
- filter, fire hydrants, mulsifier, pump casing, sprinkler, strainer, and valve bodies (including containment isolation valves)
- HTX - heat exchanger shell and access cover
- HTX - heat exchanger tubes
- diesel-drivel fire pump and fuel supply line
- CO_2 fire suppression (HPCI)
- Halon fire suppression installed in the diesel generator building (DGB)

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 and UFSAR Section 9.5.1 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.15 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's review of the fire protection sections of the LRA:

In RAI 2.3.3.15-1, the staff stated that UFSAR Section 9.5.1.4.1.4 discusses the water fire protection system, including the fixed manual suppression system hose stations with hose racks and hose reels. LRA Section 2.3.3.15 references drawing F-02315-LR, sheet 1 "Unit 1 & 2, Charcoal Adsorber System, Miscellaneous Services, Piping & Instrumentation Diagram" for license renewal scoping boundaries for the fire protection system. Drawing F-02315-LR, sheet 1 shows hose station/hose racks AOG 59 and AOG-60, and hose station/hose reels AOG-57, AOG-58, and AOG 61 in scope. Hose station/hose reel AOG-62 is shown out of scope. Therefore, the staff requested that the applicant justify hose station/hose reel AOG-62 as being out of scope.

In its response, by letter dated May 4, 2005, the applicant stated: "AOG-62 was incorrectly classified in the equipment data base (EDB) and, therefore, was not included in scope. However, AOG-62 is in scope and should have been marked on drawing F-02315-LR as within the scoping boundary."

Based on its review, the staff found the applicant's response acceptable because it adequately explains that the components in question are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a), but were inadvertently left unhighlighted on the license renewal drawing in question, F-02315-LR. The staff concluded that the components were correctly included within the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-1 is resolved.

In RAI 2.3.3.15-2, the staff stated that UFSAR Section 9.5.1.4.1.4 discusses the water fire protection system, including the fixed manual suppression system hose stations with hose racks and hose reels. In UFSAR Section 9.5.1.5, the specific fire hazards analysis for fire area MWT-1 Makeup Water Treatment states: "Manual fire fighting in the area should not be difficult. A hose line and portable fire extinguishers are available in the area to assist in manual fire fighting." LRA Section 2.3.3.15 references drawing D-02304-LR for license renewal scoping boundaries for the fire protection system. On Drawing D-02304-LR, Hose station/hose reel 2-WT-HR-#1 is shown out of scope. Therefore, the staff requested that the applicant justify this hose station/hose reel as out of scope.

In its response, by letter dated May 4, 2005, the applicant stated:

> The EDB quality classifications for credited fire protection components are B-31, B-32, B-33, B-34, B-35, and B-42. The hose reel, 2-FP-WT-HR-1, is classified as quality class D-99 (i.e., non-seismic/non-safety related). The BSEP fire protection commitment document does not identify a commitment for hose reels within the Water Treatment Building. As such, the subject hose reel does not support a License Renewal fire protection intended function, and is correctly identified as out of scope.

Based on its review, the staff found the applicant's response acceptable because it adequately explains that hose reel 2-FP-WT-HR-1 in the water treatment building is not credited to meet the requirements of 10 CFR 50.48 and is not part of the plant CLB. The staff concluded that the components were correctly excluded from within the scope of license renewal and from being subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-2 is resolved.

In RAI 2.3.3.15-3, the staff stated that UFSAR Section 9.5.1.4.1.4 discusses the water fire protection system, including the fixed automatic suppression system. In UFSAR Section 9.5.1.5, the specific fire hazards analysis for fire area Makeup Water Treatment (MWT)-1 states: “Fire protection includes an automatic sprinkler system with heads located at the ceiling level.” LRA Section 2.3.3.15 references drawing D-02304-LR for license renewal scoping boundaries for the fire protection system. On Drawing D-02304-LR (B-8), Sprinkler nozzle 764-I-J-2 is shown out of scope. Therefore, the staff requested that the applicant justify this sprinkler nozzle as out of scope.

In its response, by letter dated May 4, 2005, the applicant stated: “Sprinkler pipe was inadvertently not highlighted on Drawing D-02304. The sprinkler piping is in scope for License Renewal.”

Based on its review, the staff found the applicant's response to RAI 2.3.3.15-3 acceptable because it adequately explains that the components in question are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a), but were inadvertently not highlighted on the license renewal drawing in question, D-02304-LR. The staff concluded that the components were correctly included within the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-3 is resolved.

In RAI 2.3.3.15-4, the staff stated that UFSAR Section 9.5.1.4.1.4 discusses the water fire protection system, including the fixed manual suppression system foam-water hose stations located in the diesel generator building to provide backup suppression for the four-day tank rooms and the oil bath air filters. In UFSAR Section 9.5.1.5, the specific fire hazards analysis for fire areas DG-19 Fuel Oil Tank Cell 1, DG-20 Fuel Oil Tank Cell 2, DG-21 Fuel Oil Tank Cell 3, and DG-22 Fuel Oil Tank Cell 4 states: “Manual fire fighting could be difficult should a significant oil fire occur. Because the tanks are located below grade, access for fire fighting could be difficult. A foam standpipe is available from an adjacent area.” LRA Section 2.3.3.15 references drawing D-02301-LR for license renewal scoping boundaries for the fire protection system. On Drawing D-02301-LR, the foam hose station/hose reel AFFF-HR1 is shown out of scope. Therefore, the staff requested that the applicant justify this hose station/hose reel as out of scope.

In its response, by letter dated May 4, 2005, the applicant stated:

> The CLB requires an automatic Aqueous Film Forming Foam (AFFF) System meeting therequirements of National Fire Protection Association (NFPA)-11B to protect the fuel tank bunkers. The CLB also requires two AFFF portable concentrate stations, one to be located in the DG Building and the other in the yard area for the purpose of combating fires in the day tanks, auxiliary boiler, etc. Each portable station provides 20 minutes of AFFF. The two portable AFFF concentrate stations satisfy the licensing commitment.
>
> The piping portion of the AFFF System is in scope up to the hose reel isolation valve to maintain system integrity. Fixed foam station AFFF-HR1 is shown correctly as out of scope for License Renewal.

Based on its review, the staff found the applicant's response to RAI 2.3.3.15-4 acceptable because it adequately explains that hose reel 2-FP-AFFF-HR1 in the Diesel Generator Building is not credited to meet the requirements of 10 CFR 50.48 and is not part of the plant CLB. The staff concluded that the components were correctly excluded from the scope of license renewal and from being subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-4 is resolved.

In RAI 2.3.3.15-5, the staff stated that UFSAR Section 9.5.1.4.1.4 discusses the water fire protection system, including the fixed manual suppression system foam-water hose stations located in the diesel generator building to provide backup suppression for the four-day tank rooms and the oil bath air filters. In UFSAR Section 9.5.1.5, the specific fire hazards analysis for fire zone DG-16 Fan Room states: "Manual fire fighting should not be difficult. Water standpipes and foam standpipes are provided to assist in manual fire fighting." LRA Section 2.3.3.15 references drawing D-02302-LR "Unit 1 & 2, Diesel Generator Building, Fire Protection Foam (AFFF) System, Piping Diagram" for license renewal scoping boundaries for the Fire Protection system. On Drawing D-02302-LR, Foam hose station/hose reels AFFF-HR2 and AFFF-HR-3 are shown out of scope. Therefore, the staff requested that the applicant justify these hose station/hose reels as out of scope.

In its response, by letter dated May 4, 2005, the applicant stated:

> The CLB requires an automatic AFFF System meeting the requirements of NFPA-11B to protect the fuel tank bunkers. The CLB also requires two AFFF portable AFFF portable concentrate stations, one to be located in the Diesel Generator Building and the other in the yard area for the purpose of combating fires in the day tanks, auxiliary boiler, etc. Each portable station provides 20 minutes of AFFF. Fire Protection commitment number AF-003 requires an AFFF System and oil retaining system be added to the oil air intake filters. AFFF-HR2 and AFFF-HR3 are BSEP 05-0050 manual systems and therefore not a fire protection commitment. As such, foam hose stations AFFF-HR2 and AFFF-HR3 are correctly shown out of scope.
>
> The piping portion of the AFFF System is in scope up to the hose reel isolation valve to maintain system integrity. The hose reel supports are shown as a managed civil commodity in Table 3.5.2-10 Containments, Structures and Component Supports - Summary of Aging Management Evaluation - Diesel Generator Building. The mechanical portion of fixed position hose reels 2-FP-AFFF-HR2 and 2-FP-AFFF-HR3 are not in scope because they ares not in the current licensing basis."

Based on its review, the staff found the applicant's response to RAI 2.3.3.15-5 acceptable because it adequately explains that hose reels 2-FP-AFFF-HR2 and 2-FP-AFFF-HR3 in the Diesel Generator Building are not credited to meet the requirements of 10 CFR 50.48 and are not part of the plant CLB. The staff concluded that the components were correctly excluded from the scope of license renewal and from being subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.15-5 is resolved.

In RAI 2.3.3.15-6, the staff stated that UFSAR Section 9.5.1.4.1.4 discusses the water fire protection system, including the electric motor driven fire pump (P-2), the diesel engine driven fire pump (P-1) and the two jockey pumps (P-3 and P-4) providing water for fire suppression and fire fighting. UFSAR Section 9.5.1.4.1.5 discusses the instrumentation and control of the water supply, including the jockey pumps and the electric motor driven pump and diesel engine driven pump. LRA Section 2.3.3.15 references drawing D-04106-LR "Unit 1 & 2, Plant Fire Protection System, Piping Diagram" for license renewal scoping boundaries for the Fire Protection system. On Drawing D-04106-LR, it is unclear if the Control Panels for Pumps P-1 (Engine Driven Fire Pump), P-2 (Motor Driven Fire Pump), P-3 (Jockey Pump), and P-4 (Jockey Pump) are in scope. Therefore, the staff requested that the applicant clarify the status of these control panels, and justify exclusion if they are out of scope.

In its response, by letter dated May 4, 2005, the applicant stated that: "Electrical panels for Fire Pumps P-1 (i.e., Engine Driven), P-2 (i.e., Motor Driven) and P-3/P-4 (i.e., jockey) are in scope. The electrical enclosures are shown as managed commodities on Table 3.5.2-14 of the application."

Based on its review, the staff found the applicant's response to RAI 2.3.3.15-6 acceptable because it adequately clarifies that the components in question are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a). Therefore, the staff's concern described in RAI 2.3.3.15-6 is resolved.

In RAI 2.3.3.15-7, the staff stated that UFSAR Section 9.5.1.4.3.4 discusses propagation/damage control features that are used to prevent the unhindered spread of fire and also to protect equipment from fire exposures. License renewal section 2.3.3.15 states that physical barriers are addressed in the License Renewal review as structural commodities in Section 2.4. Therefore, the staff requested that the applicant clarify that the following have been included within the scope of license renewal, or justify the exclusion from the scope of license renewal:

(1) Impingement shields installed between exposed cables of redundant trains of safe shutdown equipment when the trains are within 5 feet vertically or 3 feet horizontally of each other.

(2) Impingement shields installed between the two fire pumps and between the diesel fire pump fuel tank and the fire pumps. (Discussed in UFSAR Section 9.5.1.5 fire hazard analysis writeup for fire area MWT-1 Makeup Water Treatment)

(3) Flame retardant coatings applied to conduit and cable trays in cable access ways and spreading areas.

(4) Fire stops in Cable Trays.

In its response, by letter dated May 4, 2005, the applicant stated that:

(1) Impingement shields are addressed within the "Fire Barrier Assembly" and "Sprayed on Coatings" commodity groups. See LRA Tables 2.4.2-6, 2.4.2-7, 2.4.2-9, 2.4.2-10, 2.4.2-11, and 2.4.2-13.

(2) Impingement shields installed between the two fire pumps and between the diesel fire pump fuel tank and the fire pumps are addressed within the "Fire Barrier Assembly" commodity group, see LRA Table 3.5.2-13. However, based on a walkdown inspection of the impingement barriers, the "Fire Barrier Assembly"between the diesel fire pump fuel tank and the fire pumps was observed to be masonry block. The LRA Table 3.5.2-14 identifies the material type of the impingement shield as only carbon steel; as such, the

Table will be revised to identify the “Fire Barrier Assembly” material type as Carbon Steel and Masonry Block. Both Fire Barrier Assemblies are addressed with the Fire Protection Program and are managed as fire barriers.

(3) Flame retardant coatings applied to conduit and cable trays are addressed within the “Fire Barrier Assembly” and “Sprayed on Coatings” commodity groups. See LRA Tables 2.4.2-6, 2.4.2-7, 2.4.2-9, 2.4.2-10, 2.4.2-11, and 2.4.2-13.

(4) Fire stops in cable trays are addressed within the “Fire Barrier Assembly” and “Sprayed on Coatings” commodity groups. See LRA Tables 2.4.2-6, 2.4.2-7, 2.4.2-9, 2.4.2-10, 2.4.2-11, and 2.4.2-13.

Based on its review, the staff found the applicant’s response to RAI 2.3.3.15-7 acceptable because it adequately clarifies that the components in question are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a). Therefore, the staff's concern described in RAI 2.3.3.15-7 is resolved.

2.3.3.15.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the fire protection system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the fire protection system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.16 Fuel Oil System

2.3.3.16.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.16, the applicant described the fuel oil (FO) system. The FO system supplies No. 2 fuel oil for use by the auxiliary boiler, diesel fire pump, and emergency diesel engines. The FO system consists of the main diesel fuel oil storage and unloading subsystem, the fire pump diesel engine fuel oil subsystem, and the auxiliary boiler fuel oil subsystem. The main fuel oil storage tank in the main diesel fuel oil storage and unloading subsystem can supply each of the DG 4-day fuel oil storage tanks with fuel to support seven days of diesel operation. The tank is not SR; however, it is within the scope for license renewal because it supports an SR function. As discussed in the UFSAR, to ensure a 7-day supply following postulated damage to the main fuel oil storage tank, fuel oil can be readily obtained by truck or rail directly to the Brunswick plant, or by barge on the Cape Fear River or Intracoastal Waterway to local docks and off-loaded into trucks for delivery to the site.

The failure of NSR SSCs in the FO system could potentially prevent the satisfactory accomplishment of an SR function. The FO system also performs functions that support fire protection. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3.16, the applicant identified the following FO system component types that are within the scope of license renewal and subject to an AMR:

- diesel-driven fire pump and fuel supply line
- valves body and tubing
- diesel fuel tank
- piping (aboveground pipe and fittings)
- valves (body and bonnet)
- tank (internal/external surface)

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 and UFSAR Section 8.3.1.1.6.2.8 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.16.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the FO system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the FO system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.17 Radioactive Floor Drains System

2.3.3.17.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.17, the applicant described the radioactive floor drains system. Buildings at BSEP are designed and constructed to serve specific purposes and contain equipment necessary for the operation of the plant and to ensure safety to the general public. Each building is fitted with the necessary support equipment to ensure that the function of the building is fulfilled. The layout of drains and routing of drains to sumps ensures that water does not accumulate on floors and that radiologically contaminated water does not mix with non-contaminated water. The function of the radioactive floor drains system is to route all floor drains to the proper disposal facility. The contaminated floor drainage system includes all floor drains from the reactor building, turbine building, AOG building, the radwaste building, and other floor drains having a potential for radioactive spillage. The collected drainage is transferred to the radwaste facility for processing.

The radioactive floor drains system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the radioactive floor drains system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the radioactive floor drains system performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.3-14, the applicant identified the following radioactive floor drains system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- flow orifice (body)
- pump (casing)
- tank (shell)
- drain system sump pumps

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA 2.3.3.17 and UFSAR Section 9.3.3 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In reviewing LRA Section 2.3.3.17, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.17-1, the staff stated that license renewal boundary drawing D-02543-LR, sheet 1B, location E-8, shows dirty radiological waste (DRW) drain piping which receives fluid from in-scope drains on the 80-foot elevation and connects to the in-scope 6-inch DRW drain to the RHR sump. The DRW drain piping is not identified as being in scope, even though it is connected to in-scope piping. Therefore, the staff requested that the applicant provide additional information to justify its determination to exclude the DRW piping at location E-8 from within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the subject piping is within the radioactive floor drains system license renewal scoping boundary and subject to an AMR in accordance with 10 CFR 54.4(a)(2).

Based on its review, the staff found the applicant's response acceptable because the subject DRW piping is within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.17-1 is resolved.

In RAI 2.3.3.17-2, the staff stated that on license renewal drawing D 02533 LR, sheet 2, locations B-8 and C-8, for the lines identified below, the transition locations from out-of-scope to in-scope is inconsistent with the continuation drawings indicated. Therefore, the staff requested that the applicant provide additional information to resolve the apparent inconsistency in the license renewal boundary drawings.

- 1-G16-507-4-160 (D25043-1B, C-8)
- 1-G16-510-2-160 (D25046, C-1)
- 1-G16-511-2-160 (D25046, C-8)
- 2-G16-507-4-160 (D2543-1B, C-8)
- 2-G16-511-2-160 (D2546, C-8)

In its response, by letter dated May 4, 2005, the applicant stated:

> Lines 1-G16-503-3-160 and 2-G16-503-4-160, on drawing D-02533-LR, sheet 2, support the function of detecting leakage from the RCPB in accordance with Regulatory Guide (RG) 1.45. (See LRA page 2.3-77.) The connected piping and floor drain collection tank, highlighted on drawing D-02533-LR, sheet 2, at locations B-8 and C-8, were credited in the seismic stress analysis for RG 1.45 compliance. See the response to RAI 2.3.3.17-3 for additional information. Additionally, the portion of 1/2-G16-507 and 511 and 1-G16-510 in the reactor building as well as in the radwaste pipe tunnel in the vicinity of safety related SW valves are non-safety related components, which by virtue of their location, may cause adverse spatial interactions with safety related components and, therefore, are within the scoping boundary.

Based on its review, the staff agrees with the applicant’s clarification discussed above and finds the applicant's response acceptable. Therefore, the staff's concern described in RAI 2.3.3.17-2 is resolved.

In RAI 2.3.3.17-3, the staff stated that LRA Table 2.3.3.3-14, "Component/Commodity Groups Requiring Aging Management Review and Their Intended Functions for the Radioactive Floor Drain System," identifies the pump casing and floor drain tank as within the scope of license renewal. On drawing D02533-LR, sheet 2, at location B-5, the line (213-4-161, 240-4-160) from the floor drain collector tank to the suction of the floor drain collector pump is not identified as within the scope of license renewal. Additionally, several other lines (234-6-160 at D-8, V71 to radwaste building wall, 528-3-160 at C-7, 532-3-160 at A-7, and 2-G16-958-3-160 at C-7, 223-6-160, 250-3-160) leading to and from the drain tank are not included within the scope of license renewal. Therefore, the staff requested that the applicant provide information to justify its determination to exclude these lines and the floor drain collector pump casing from within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the floor drain collection tank, 2-G16-A006, on drawing D-02533-LR, sheet 2, at location B-5, was credited in the seismic stress analysis supporting the function of detecting leakage from the RCPB in accordance with RG 1.45. The tank and subject piping is associated with the liquid waste processing system described in LRA Section 2.3.3.24. As shown on LRA Table 2.3.3-19, tanks in the liquid waste processing system have been assigned the M-1 intended function, "Provide pressure-retaining boundary." BSEP methodology typically assigned the M-1 component intended function to pressure-retaining mechanical components designated in the EDB as NSR whose failure could impact an SR function. While the M-4 function designation may have been more appropriate for the floor drain collection tank, the M-1 function designation is conservative; and applicable AMRs are directed towards maintaining pressure boundary integrity. The portions of 2-G16-528/532-3-160 credited in the seismic analysis are within the scope of license renewal and appropriately highlighted on drawing D-02533-LR, sheet 2. The remaining NSR piping and components noted in RAI 2.3.3.17-3 are not included in the seismic analysis terminating at 2-G16-A006 and, therefore, have no intended function.

Based on its review, the staff found the applicant's response acceptable because the applicant has provided justification as to why the components in question are not included within the seismic analysis and have no intended function and thereby do not need to be included within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.17-3 is resolved.

2.3.3.17.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the radioactive floor drains system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the radioactive floor drains system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.18 Radioactive Equipment Drains System

2.3.3.18.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.18, the applicant described the radioactive equipment drains system. The buildings at BSEP are designed and constructed to serve specific purposes and contain equipment necessary for the operation of the plant and to ensure safety to the general public. Each building is fitted with the necessary support equipment to ensure that the function of the building is fulfilled. The layout of drains and routing of drains to sumps ensure that water does not accumulate on floors and that radiologically contaminated water does not mix with non-contaminated water. The function of the radioactive equipment drains system is to route all equipment drains to the proper disposal facility. Reactor building equipment drains are collected in two separate subsystems. One handles drainage from all equipment drains located in the drywell; the other handles drainage from equipment drains located in the reactor building. Individual drywell equipment drain lines collect in branch lines and discharge to the drywell equipment drain sump; sump pumps transfer the collected fluid to the radwaste system. The system includes automatic containment isolation valves on lines penetrating the primary containment. These valves provide the primary containment isolation function following postulated DBEs.

The radioactive equipment drains system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the radioactive equipment drains system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the radioactive equipment drains system performs functions that support EQ.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)
- provides structural support/seismic integrity

In LRA Table 2.3.3-15, the applicant identified the following radioactive equipment drains system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- heat exchanger (shell and access cover)
- flow orifice (body)
- pump (casing)
- tank (shell)

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 and UFSAR Section 9.3.3.3 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In reviewing LRA Section 2.3.3.18, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 (a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.18-1, the staff stated that LRA Table 2.3.3.3-15, "Component/Commodity Groups Requiring Aging Management Review and Their Intended Functions for the Radioactive Equipment Drains System," identified the equipment drain tank as in scope for license renewal. On drawings D-25043-LR, sheet 1A; and D-02543-LR, sheet 1A, at location A-7, the equipment drain tank shows several lines entering (8" CRW drain, 6" CV-FO11, 2" 1-160) and two exiting (4" CRW vent and 524-3-161 at A-7) that are not within the license renewal boundary. Therefore, the staff requested that the applicant provide additional information to justify its determination to exclude these lines from within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated:

> The Clean Radwaste (CRW) piping described in the Radioactive Equipment Drains System collects treated water from equipment leak-off for transfer to the Radwaste System. The BSEP 10 CFR 54.4(a)(2) scoping methodology allows for the exclusion from applicability of non-safety piping and components that are not normally liquid or steam-filled during operation (e.g. normally empty pipe) with a low probability of failure during actual use. Based on these considerations and operating experience, normally empty, unpressurized, non-safety CRW piping and components do not present a spatial interaction hazard for safety related components.
>
> The Equipment Drain Tanks and connected piping, shown on drawings D-02543-LR, Sheet 1A, and D-25043-LR, Sheet 1A, illustrate this scoping approach. The Equipment Drain Tanks are normally partially filled with an overflow that vents to the atmospheric pressure Radioactive Floor Drain System through 1/2-G16-524-3-161, which has no intended function. The piping exiting the Equipment Drain Tanks and connecting to the equipment drain pumps, 1/2-G16-C007, is normally liquid-filled and within the License Renewal scoping boundary. The piping down stream of the Equipment Drain Pump is normally liquid filled, can be pressurized and is within the License Renewal scoping boundary. The only lines entering the top of the Equipment Drain Tanks shown as in-scope for License Renewal is the return line from the Equipment Drain Tank cooling heat exchanger, 1/2-G16-B002, which was conservatively assumed to be liquid-filled and pressurized.
>
> In summary, the portion of the Radioactive Equipment Drains System marked, on D-02543-LR, Sheet 1A, and D-25043-LR, Sheet 1A at Location A-7, as being within the License Renewal scoping boundary is for compliance with 10 CFR 54.4(a)(2).

Based on its review, the staff found the applicant's response to RAI 2.3.3.18-1 acceptable, becasue the subject equipment drain tanks and their associated piping: are non-safety related components; do not perform an intended function which satisfies any one of the 10 CFR 54.4(a) criteria; and do not perform a spatial interaction hazard for safety related components. Therefore, the staff's concern described in RAI 2.3.3.26-1 are resolved

Based on its review, the staff found the applicant’s response to RAI 2.3.3.18-1 acceptable because the subject equipment drain tanks and their associated piping are non-safety related components that do not present a spacial interaction hazard for safety related components and, thus, do not perform an intended function pursuant to the 10 CFR 54.4(a) criteria. Therefore, the staff’s concern described in RAI 2.3.3.26-1 are resolved.

In RAI 2.3.3.18-2, the staff stated that license renewal drawing D-25043-LR, sheet 1A, location E-5, identifies a portion of drain piping as being within the scope of license renewal. However, the CRW line into which it flows to return to the equipment drain tank is not shown as being within scope. Therefore, the staff requested that the applicant provide additional information to justify its determination to exclude this piping from within the scope of license renewal. Also, the same drain line shown on Unit 2 drawing D-02543-LR, sheet 1A, location E-4, is not within the scope of license renewal. The applicant was also requested to provide a rationale as to why the same drain line on Unit 2 is not within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the piping connected to hub-drain, C45HD, on drawing D-25043-LR, sheet 1A, at location E-5, was marked in error as being within the license renewal scoping boundary. This piping is normally empty, unpressurized, NSR CRW piping with no intended function. The corresponding Unit 2 components are correctly represented on D-02543-LR, sheet 1A. Information provided in response to RAI 2.3.3.18-1 provides a more complete discussion of 10 CFR 54.4(a)(2) scoping evaluations for the radioactive equipment drains system.

Based on its review, the staff found the applicant's response acceptable, because the drawings were labeled in error. This response is consistent with RAI 2.3.3.18-1 which was also found to be acceptable. Therefore, the staff's concerns described in RAI 2.3.3.18-2 are resolved.

In RAI 2.3.3.18-3, the staff stated that license renewal drawing D-02531-LR, sheet 1, location C-7, shows the waste collector tank as being within the scope of license renewal because it provides a pressure boundary function. There are several lines that exit the tank that are not included within the scope of license renewal. Therefore, the staff requested that the applicant provide additional information to justify its reason for excluding the piping identified below and associated isolation valves from the scope of license renewal.

- Line 14-4-161 and valve F036
- Line 35-4-161 and valve F033, F143
- Line 677-1/2-161 and its first isolation valve
- Line 2G41-59-8-154
- Instrument level transmitter N026 and valve V338
- Waste collector pump suction line 1-4-152 and valve F034
- Line 9-8-160 and 2-inch CDW/SCRD cap

In its response, by letter dated May 4, 2005, the applicant stated:

> The Waste Collection Tank, 2-G16-A002, on drawing D-02531-LR, Sheet 1, at Location C-7,was credited in the seismic stress analysis as supporting the function of detecting leakage from the RCPB in accordance with RG 1.45. The tank and subject piping is associated with the Liquid Waste Processing System described in LRA Section 2.3.3.24. As shown on LRA Table 2.3.3-19, tanks in the Liquid Waste Processing System have

been assigned the M-1 intended function, "Provide pressure-retaining boundary." BSEP methodology typically assigned the M-1 component intended function to pressure retaining mechanical components designated in the EDB as non-safety whose failure could impact a safety function. While the M-4 function designation may have been more appropriate for the Waste Collection Tank, the M-1 function designation is conservative and applicable aging management reviews are directed towards maintaining pressure boundary integrity. The Waste Collection Pump suction line, 2-G16-1-4-152, and isolation valve, 2-G16-F034, are within the system scoping boundary and BSEP 05-0050 Enclosure 1 Page 45 of 87 should have been highlighted on drawing D-02531-LR, Sheet 1. The remaining non-safety piping and components noted in RAI 2.3.3.18-3 are not included in the seismic analysis terminating at 2-G16-A002 and, therefore, have no intended function.

Based on its review, the staff found the applicant's response acceptable because the applicant has corrected errors with the waste collection pump suction line, 2-G16-1-4-152, and isolation valve, 2-G16-F034. The remaining components are consistent with the response for those similar items in RAI 2.3.3.18-1 and 2 and are also acceptable. Therefore, the staff's concerns described in RAI 2.3.3.18-3 are resolved.

2.3.3.18.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the radioactive equipment drains system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the radioactive equipment drains system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Makeup Water Treatment System

2.3.3.19.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.19, the applicant described the makeup water treatment system (MWTS). The MWTS supplies all normal requirements for demineralized water throughout the plant. The water supply to the MWTS is the county water system (formerly the supply was from the well water system). Piping in the MWTS is used to supply county water directly to the fire protection water tank for makeup. Demineralized water from the MWTS is supplied to the 200,000-gallon demineralized water storage tank from which redundant pumps distribute it through the plant demineralized water piping. The MWTS is a shared system between units providing a supply of high purity water free of materials that could become radioactive.

The MWTS contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the MWTS could potentially prevent the satisfactory accomplishment of an SR function. In addition, the MWTS performs functions that support fire protection. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-16, the applicant identified the following MWTS component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- piping (piping and fittings)
- valves (body and bonnet)
- tank (shell)

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 and UFSAR Section 9.2.3 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from within the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In reviewing LRA Section 2.3.3.19, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results. Therefore, by letter to the applicant dated April 8, 2005, the staff issued RAIs concerning the specific issues to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a)(1). The following paragraphs describe the staff's RAIs and the applicant's related responses.

In RAI 2.3.3.19-1, the staff stated that LRA Table 2.3.3-16 identifies the intended function for demineralized water system tank (shell) components requiring aging management review as M-1, "Provide pressure-retaining boundary." License renewal boundary drawings D-02040-LR, sheet 1A (quadrant C-6), and D-02040-LR, sheet 1B (quadrant C-4), show Unit 1 and 2 CST shells as being within the scope of license renewal. However, some of the Unit 1 and 2 CST shell nozzle locations are connected to non-isolable portions that are shown as not being within scope of license renewal and some isolable piping that are shown as not within scope up to and including the first isolation valve. Therefore, the staff requested that the applicant provide additional information justifying the in-scope boundaries selected for the non-isolable piping connected to CST shell nozzles.

In its response, by letter dated May 4, 2005, the applicant stated:

> The CSTs are non-safety related, located in the yard and in the scope of License Renewal under 10 CFR 54.4(a)(3), for compliance with Station Blackout (SBO) requirements. UFSAR Section 9.2.6.2 describes the configuration of the CST, specifically

identifying 12 inch and 16 inch piping with connection centerlines to the tank at the 10 foot level that preserve the inventory below that point for use by the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems. The UFSAR notes that the physical arrangement of the tank and associated piping assures a reserve capacity of 74,000 gallons, and that additional reserve capacity is provided by an administrative limit at the 10 foot level to provide a total HPCI/RCIC reserve inventory of 105,700 gallons. The NRC Safety Evaluation Report (SER) for SBO compliance notes that the 10 foot level assures an inventory greater than 103,380 gallons, and is therefore sufficient for the coping duration. A review of the BSEP Extended Power Uprate (EPUR) submittal confirms that these limits were not affected by uprated power conditions. Based on these considerations, BSEP is including piping connected to the Unit 1 and 2 CSTs at or below the 10 foot level in the scope of License Renewal. In addition to piping connected to nozzles N-1 and N-12, which are already in scope, this includes the following connected piping up to their first isolation valves:

- Condensate transfer pump suction line connected to nozzle N-2,
- CRD pump condensate return line connected to N-3,
- Condensate supply line connected to nozzle N-9,
- Unit 1 and 2 CST cross-connect lines connected to nozzles N-8 and N-13,
- HPCI/RCIC test return line connected to nozzle N-14, and
- Drain line connected to nozzle N-5.

The tank volume above the 10 foot level is not needed for compliance with SBO, and piping connected above this point does not satisfy any license renewal scoping criteria.

The piping and equipment included in license renewal scope, as identified above, will be managed internally with the Water Chemistry and the One-Time Inspection Programs, and externally with the Systems Monitoring and Buried Piping and Tanks Inspection Programs.

Based on its review, the staff found the applicant's response acceptable because the applicant confirmed that the tank volume below the CST 10-foot elevation required for compliance with SBO, and piping up to their first isolation valves piping connected to the Units 1 and 2 CSTs at or below the CST 10-foot elevation will be included in the scope of license renewal. Therefore, because the remaining CST nozzles and attached piping will not result in a loss of the tank shell pressure-retaining function to deliver sufficient water to the HPCI System during an SBO, the staff's concerns described in RAI 2.3.3.19-1 are resolved.

In RAI 2.3.3.19-2, the staff stated that LRA Table 2.3.3 16 identifies the intended function for MWTS piping components requiring aging management review as M-1 “Provide pressure-retaining boundary.” License renewal boundary drawing D-25043-LR, sheet 1A (quadrants F-4 and F-5), identifies a common drain header and selected connecting RWCU drain piping as within the scope of license renewal. For two RWCU drain lines, the in-scope boundary extends to piping shown on drawing D-25028-2B (quadrants B-2 and B-6). This is inconsistent with sheet 1A of license renewal boundary drawing D-02543-LR (quadrants F-4 and F-5) which shows this piping as not within the scope of license renewal. Drawing D-25028-2B is not identified in LRA Section 2.3.3.19 as an MWST boundary drawing for license renewal and was not made available for staff review. Therefore, the staff requested that the applicant provide additional information to explain these inconsistencies and the basis for the boundary determinations.

In its response, by letter dated May 4, 2005, the applicant stated that the common drain header to C45HD and connecting RWCU drain piping to D-25028-2B shown on D-25043-LR, sheet 1A, at coordinates F-4 and F-5, is not within the scope of license renewal and were inadvertently highlighted. The staff found the applicant's response acceptable and, therefore, the staff's concern described in RAI 2.3.3.19-2 resolved.

2.3.3.19.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the MWTS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the MWTS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.20 Chlorination System

2.3.3.20.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.20, the applicant described the chlorination (CL) system. The CL system provides a means of treating the SW and CW systems against biological growth. For control room habitability considerations, chlorine detectors are mounted at the control room air intakes, and attached to the wall of the SW intake structure immediately adjacent to the rail siding where the chlorine tank car is located. In the event high chlorine is detected, local and control room alarms are activated, and the control room isolation dampers automatically close. The CL system has a total of six components that place portions of this system within the scope of license renewal. Two of the six are electrical components that actuate isolation valves required to maintain the function of an SR system (the SW system). Scoping and screening of electrical/I&C components/commodities are addressed in LRA Section 2.5. The remaining components are panels designated quality class due to seismic considerations only. The panels are classified as seismically analyzed to avoid adverse interactions with SR SSCs during an earthquake. Panels are addressed as civil commodities in LRA Section 2.4.

The CL system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the CL system could potentially prevent the satisfactory accomplishment of an SR function. The CL system components that are within the scope of license renewal are electrical and I&C components/commodities or civil commodities, which are discussed in LRA Sections 2.5 and 2.4, respectively.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and UFSAR Section 10.4.5.2 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.20.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the CL system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the CL system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.21 Potable Water System

2.3.3.21.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.21, the applicant described the potable water system (PWS). The PWS supplies the necessary water for onsite drinking and sanitary services and makeup to various components in miscellaneous plant systems. This system is supplied by the county water supply. The PWS is not essential for safe shutdown of the plant and does not satisfy any SR quality criteria. Based on the license renewal review, this system has components that are within the scope of license renewal because of potential spatial interactions with SR components. A potable water line traverses the control building battery rooms to supply water in the radwaste building. These components have been included within the scope of license renewal as a result of the 10 CFR 54.4(a)(2) review.

The failure of NSR SSCs in the PWS could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-17, the applicant identified the following PWS component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- tank (shell)

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and USFAR Section 9.4.2 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.21.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the PWS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the PWS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.22 Process Radiation Monitoring System

2.3.3.22.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.22, the applicant described the process radiation monitoring (PRM) system. The PRM system is designed to continuously monitor radioactivity within the plant. A number of radiation monitors and monitoring systems are provided on process liquid and gas lines that may serve as discharge routes for radioactive materials. These include the following: (1) main steam line radiation monitoring system, (2) condenser off-gas radiation monitoring system, (3) main stack radiation monitoring system, (4) liquid process radiation monitoring system, (5) reactor building ventilation radiation monitoring system, (6) turbine building ventilation radiation monitoring system, and (7) AOG charcoal absorber system gaseous discharge monitoring system. The main steam line monitors annunciate alarms in the control room when the radiation level of the steam surpasses a certain level. The processes are continuously sampled for particulate and iodine, and the samples are routinely analyzed. SR process radiation monitors in the reactor building exhaust can initiate reactor building isolation and startup of the SGTS. Monitors in the SW system are used to assure that effluents will have radiation levels below preestablished limits.

The PRM system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the PRM system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the PRM system performs functions that support EQ. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-18, the applicant identified the following PRM system component types that are within the scope of license renewal and subject to an AMR: closed-cycle cooling water system (piping specialties).

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22 and UFSAR Sections 11.5.1 through 11.5.8 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.22.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the PRM system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the PRM system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.23 Area Radiation Monitoring System

2.3.3.23.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.23, the applicant described the area radiation monitoring (ARM) system. The ARM system is designed to detect, indicate, and record (as required) the radiation level of selected points throughout BSEP. Permanently mounted system instrument channels actuate annunciators in the control room when the sensed radiation level exceeds upscale or downscale trip points to warn personnel of increased radiation levels or equipment malfunction. The system consists of the following: (1) ARM system, (2) drywell high range area monitoring system, and (3) airborne radiation monitoring system. The ARM system detectors are located strategically throughout the site. These detectors are located based upon the need to furnish information relative to gamma levels in plant areas. The detectors provide a long-term, post-accident monitoring function. The airborne radiation monitoring system uses fixed instruments to monitor particulates, halogens, and noble gases in the reactor building vents and in the drywell. In addition, continuous air monitors are located in critical areas of the plant and may be moved as conditions require.

The ARM system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the ARM system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the ARM system performs functions that support EQ.

The ARM system components that are within the scope of license renewal and subject to an AMR are addressed as electrical and I&C component/commodities or civil commodities in LRA Section 2.5 or 2.4, respectively.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and UFSAR Section 112.3.4 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.23.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the ARM system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the ARM system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.24 Liquid Waste Processing System

2.3.3.24.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.24, the applicant described the liquid waste processing system. The liquid waste processing system functions to collect, treat, and process potentially radioactive liquid waste for reuse or controlled discharge in compliance with established regulatory requirements. The system processes radioactive or potentially radioactive liquid wastes of different purities and chemical conditions. Principal sources of liquid wastes are equipment drains (high purity), floor drains (medium to low purity), chemical wastes (very low purity), detergent, and oily liquid drains. Liquid radwaste is classified in two categories; clean radioactive waste (CRW) and dirty radioactive waste (DRW). CRW has the following properties: low or high activities, low conductivity, low solid content and neutral pH. DRW has the following properties: low activity, moderate conductivity, moderate solid content and neutral pH. The properties of each category determine the treatment and processing of the liquid waste collected by this system.

The failure of NSR SSCs in the liquid waste processing system could potentially prevent the satisfactory accomplishment of an SR function. The liquid waste processing system also performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.3-19, the applicant identified the following liquid waste processing system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- immersion element (pressure reataining housing)
- tank (shell)

2.3.3.24.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.24 and UFSAR Section 11.2 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.24 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.24-1, dated April 8, 2005, the staff stated that LRA Table 2.3.3.3-19, "Component/Commodity Groups Requiring Aging Management Review and Their Intended Functions for the Liquid Waste Processing System," identified several tanks within the scope of license renewal because they provide the pressure boundary function. License renewal drawing D-02534-LR, sheet 1, locations E-3 and E-5, show waste neutralizer tanks A and C, respectively. Drawing D-02534-LR, sheet 2, locations E-4 and E-6, show waste neutralizer tanks B and D, respectively. Drawing D-02492-LR, location B-3, shows the concentrated waste tank. Each drawing shows several lines that enter each tank that are not identified as within scope for license renewal. Therefore, the staff requested that the applicant provide additional information to justify its reason for excluding the lines, identified below, up to the closest isolation valve from within the scope of license renewal.

"A" Waste Neutralizer Tank

- Line 297-6-161 and valves F224A, V1379
- Line 302-3-Z-5 and valves, V14A, F231A, V1086
- Line 338-8-161
- Line 292-4-161, valve F222A
- Line 337-8-161 (cross tie between A and C tanks)

"C" Waste Neutralizer Tank

- Line 291-4-161, valve F222C
- Line 296-6-161, valve F224C
- Line 301-3-Z-5, valves V14C, V13C, F231C
- Line 336-8-161

"B" Waste Neutralizer Tank

- Line 299-6-161, valve F224B
- Line 304-3-Z-5, valves V14B, V13B,V1087, F231B
- Line 338-8-161
- Line 292-4-161, valve F222B
- Line 339-8-161 (cross tie between B and D tanks)

"D" Waste Neutralizer Tank

- Line 293-4-161, valve F222D
- Line 296-6-161, valve F224D
- Line 303-3-Z-5, valves V14D, V13D, F231D
- Line 336-8-161

Concentrated Waste Tank Drawing

- Line 997-2-162
- Line 353-1 ½-162, valve F281
- Line 355-3-160
- Valve V5019

In its response, by letter dated May 4, 2005, the applicant stated that the stainless steel waste neutralizer tanks, 2-G16-A025A/B/C/D, on drawings D-2534-LR, sheets 1 and 2, and concentrated waste tank, 2-G16-A026, on drawing D-02492-LR are NSR components in the liquid waste processing system. BSEP conservatively brought these tanks within the scope of license renewal on the basis of their being seismically analyzed to assure continued function during an earthquake. A review of the licensing basis of these tanks shows (1) the applicant agreed to a seismic design with the Atomic Energy Commission/Division of Reactor Licensing during evaluation of the radwaste system design against 10 CFR Part 20 limits, and (2) that their failure would not result in exceeding 10 CFR Part 100 limits or adversely impacting any SR function. The license renewal boundaries reflected in the license renewal boundary drawings are limited to the tanks and connected piping included in the seismic design, consistent with the design and licensing basis.

Based on its review, the staff found the applicant's response acceptable because NSR piping and components noted in RAI 2.3.3.24-1 are not included in the seismic analysis and do not perform any intended function within the meaning of the 10 CFR 54.4(a) criteria. Therefore, the staff's concern described in RAI 2.3.3.24-1 is resolved.

2.3.3.24.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the liquid waste processing system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the liquid waste processing system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.25 Spent Fuel System

2.3.3.25.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.25, the applicant described the spent fuel system. The spent fuel system includes the new fuel racks, spent fuel racks, underwater equipment storage racks; the spent fuel shipping cask; and associated handling equipment. The new and spent fuel storage racks are designed to maintain their structural integrity in the event of an earthquake and to avoid criticality of the fuel. The spent fuel storage racks are classified as SR. In the license renewal review, the spent fuel storage racks and equipment storage racks are evaluated as structures and are addressed in SER Section 2.4. The new fuel storage racks do not perform any intended functions for license renewal.

The spent fuel system components that are within the scope of license renewal and subject to an AMR are evaluated as structural components in LRA Section 2.4.

2.3.3.25.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25 and UFSAR Sections 9.1.2 and 2.4 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.25.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the spent fuel system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the spent fuel system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.26 Fuel Pool Cooling and Cleanup System

2.3.3.26.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.26, the applicant described the fuel pool cooling and cleanup system. The fuel pool cooling and cleanup system cools the spent fuel storage pool by transferring decay heat through heat exchangers to the reactor building closed cooling water system. During refueling operations, the system is also capable of cooling the reactor cavity and dryer separator storage pit. Water purity and clarity in the storage pool, reactor well, and dryer-separator storage pit are maintained by filters and demineralizers. The system consists of two fuel pool cooling pumps, two heat exchangers, two filter demineralizers, two skimmer surge tanks, and associated piping, valves, and instrumentation. The pumps circulate the pool water in a closed loop, taking suction from the skimmer surge tanks, through the heat exchangers, circulating the water through the filter demineralizer and discharging it through diffusers at the bottom of the fuel pool and reactor well.

The fuel pool cooling and cleanup system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the fuel pool cooling and cleanup system could potentially prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides flow restriction (throttle)

In LRA Table 2.3.3-20, the applicant identified the following fuel pool cooling and cleanup system component types that are within the scope of license renewal and subject to an AMR:

- piping (piping, fittings, and flanges)
- valves (check and hand valves) (body and bonnet)
- heat exchanger (shell and access cover)
- heat exchanger (channel head and access cover)
- pump (casing)

2.3.3.26.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.26 and UFSAR Section 9.1.3 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.26 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.26-1, dated April 8, 2005, the staff stated that UFSAR Section 9.1.3.3 states that there are non-seismic drain connections located in the refueling canal between the fuel pool inner gate and the barrier that could drain the fuel pool below the top of the stored fuel if a seismic event occurred when the fuel pool gates are removed for refueling. Plugs are installed in these drain connections during refueling to prevent loss of water below the elevation of the top of the barrier after a seismic event. However, the drain lines in question, G41-75-1-1/2-161, G41-108-3-161, 111-1 and 1/2-161, 107-1 and 1/2-161, and 82-1-161, shown on drawings D-25049, Sheet 1B, location D-4, and D-02549 sheet 1B, location D-4, respectively, are not identified as being within scope for license renewal. Therefore, the staff requested that the applicant provide additional information to justify its reason for excluding these sections of drain piping from the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated:

> As noted in USFAR Section 9.1.3.3, the design of the fuel pool places the top of the stored fuel at a lower elevation than the top of the barrier located between the reactor well and the fuel storage pool. However, non-seismic drain connections located in the refueling canal between the fuel pool inner gate and the barrier could drain the fuel pool below the top of the stored fuel if a seismic event occurred when the fuel pool gates are removed for refueling.
>
> Because the subject lines are non-safety and not seismically designed, plugs are installed into G41-75-1-1/2-161 and G41-108-3-161 during refueling to prevent the loss of fuel pool water below the elevation of the top of the barrier after a seismic event. G41-111-1-1/2-161, in each unit, is on the vessel side of this barrier and drain well above the required level. There is a baffle on top of the barrier between G41-75-1-1/2-161 and G41-111-1-1/2-161 that ensures the fuel pool water level is adequate without plugging of G41-111-1-1/2-161. G41-82-1-161 is a 1-inch stainless steel leak-off monitoring line entirely imbedded in concrete that drains back into fuel pool leak-off monitoring. Even if these non-safety drain lines were to experience age-related degradation, no loss of intended function would occur.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.26-1 acceptable, because, the subject lines are non-safety related components and do not present a spatial interaction hazard for safety related components, thus, do not perform an intended function within the meaning of the 10 CFR 54.4(a) criteria. Furthermore, these lines are not filled with liquid or steam during plant operation,. Therefore, the staff's concerns described in RAI 2.3.3.26-1 are resolved.

2.3.3.26.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the fuel pool cooling and cleanup system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the fuel pool cooling and cleanup system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.27 HVAC Diesel Generator Building

2.3.3.27.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.27, the applicant described the HVAC diesel generator building. The purpose of the HVAC diesel generator building is to maintain temperature conditions to allow for optimum operation of equipment located in the diesel generator building and fuel oil storage tank vault while providing comfort and safety for attendant personnel even during design-basis conditions. This system supplies ventilation for the DG cells, associated 4160 VAC emergency switchgear rooms, 480 VAC emergency switchgear rooms, diesel generator building basement area, and the tank vault area.

The HVAC diesel generator building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the HVAC diesel generator building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the HVAC diesel generator building performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity

In LRA Table 2.3.3-21, the applicant identified the following HVAC diesel generator building component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)
- air receiver (shell and access cover)
- duct (duct fittings, access doors, and closure bolts)

- duct (equipment frames and housing)
- duct (seals in dampers and doors)

2.3.3.27.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.27 and UFSAR Section 9.4.7 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) . The staff did not identify any omissions.

2.3.3.27.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HVAC diesel generator building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC diesel generator building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.28 HVAC Reactor Building

2.3.3.28.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.28, the applicant described the HVAC reactor building. The HVAC reactor building system consists of two basic systems: the normal system and the emergency cooling system. During normal operation, the HVAC reactor building equipment provides a suitable ambient temperature for plant personnel and equipment by providing “once through” ventilation and cooling using outside air. The system maintains a negative pressure on the reactor building. The primary containment cooling system uses NSR fan coil cooling units, cooled by RBCCW, to provide drywell cooling during normal reactor operation. The drywell and torus purge subsystem can be used to purge primary containment via either a purge system exhaust fan or the standby gas treatment system. The reactor building emergency cooling subsystem provides SR cooling for the RHR, HPCI, RCIC, and CS rooms to maintain the environment in those areas required for operation of equipment during emergency operation. Dampers in the system operate to maintain secondary containment integrity in response to an accident signal. In the accident mode, the reactor building ventilation normal supply and exhaust equipment is shut down and the duct isolation dampers at the reactor building pressure boundaries are closed (secondary containment isolation). The SGTS is operated to maintain a negative pressure in the reactor building. During this mode, the reactor building HVAC system performs an SR function; since it supports limiting the release of radioactivity and provides cooling to SR equipment of the core standby cooling systems following DBEs.

The HVAC reactor building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the HVAC reactor building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the HVAC reactor building performs functions that support fire protection and EQ.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity
- provides heat transfer

In LRA Table 2.3.3-22, the applicant identified the following HVAC reactor building component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (including check valves and containment isolation) (body and bonnet)
- air receiver (shell and access cover)
- duct (duct fittings, access doors, damper housings, and closure bolts)
- duct (equipment frames and housing, including fan housings)
- duct (flexible collars between ducts and fans)
- duct (seals in dampers and doors)
- air handler heating/cooling (heating/cooling coils)
- piping (piping and fittings)
- filters (housing and supports)
- filters (elastomer seals)

2.3.3.28.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.28 and UFSAR Sections 9.4.2, 9.4.3, and 9.4.6 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and need to be identified in LRA Table 2.3.3-22. The staff did not identify any omissions.

2.3.3.28.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HVAC reactor building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC reactor building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.29 HVAC Service Water Intake Structure

2.3.3.29.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.29, the applicant described the HVAC service water intake structure. The HVAC service water intake structure consists of two 100-percent capacity independent ventilation systems (one for each unit). Each independent system contains discharge fans, discharge dampers, associated electrical equipment, instrumentation and controls, and supply air openings with bird screens. The system is necessary to control the environment in SR equipment areas so that contained SR equipment can perform its SR function. The HVAC service water intake structure provides ventilation and cooling of the SW intake structure for proper operation of SW system equipment; however, the fans are not ducted and do not have an associated pressure boundary.

The HVAC service water intake structure contains SR components that are relied upon to remain functional during and following DBEs.

The HVAC service water intake structure components that are within the scope of license renewal and subject to an AMR are addressed as electrical and I&C component/commodities or civil commodities in Sections 2.5 and 2.4, respectively.

2.3.3.29.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.29 and UFSAR Section 9.4.10.2.7 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff’s review of LRA Section 2.3.3.29 identified an area in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The applicant responded to the staff’s RAI as discussed below.

In RAI 2.3.3.29-1, dated May 18, 2005, the staff requested that the applicant clarify whether all the system components, including discharge fan housings, discharge damper housings, screens (bird screens) for air intake (supply air) and exhaust structures are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response, by letter dated June 14, 2005, the applicant stated:

> SWIS fans 1-VA-1A-EF-SWIS and 2-VA-2A-EF-SWIS, including fans, dampers, bird screens, and mountings/supports are within the scope of license renewal in accordance with 10 CFR 54.4(a). The SWIS fans, dampers, and bird screens are not ducted, but are mounted in a shrouded housing directly into an opening in the SWIS wall. Considering this configuration, the initial aging management approach reflected in the LRA was to consider that the fans and dampers were active, and the passive features were essentially mounting/support features and would be addressed as part of the SWIS building structure. BSEP has revised this approach to specifically address the subcomponents that the NRC has identified (i.e., fan and damper housings and bird screens) in the AMR for SWIS Auxiliary Systems.
>
> This revision modifies the discussion for the Heating, Ventilation, and Air Conditioning (HVAC) system for the SWIS described in LRA Section 2.3.3.29 to reflect that the system includes fan and damper housings, bird screens, and mountings/supports that are passive, long-lived features requiring AMR in accordance with 10 CFR 54.21(a)(1). Accordingly, three line items (i.e., one for fan housings, one for damper housings, and one for bird screens) will be added to the AMR associated with LRA Table 3.3.2-24. These line items are provided on the following page.
>
> The Systems Monitoring Program is described in LRA Subsection B.2.29, and includes criteria applicable to the components and aging effects addressed herein. Structural supports and mounting of the fan/damper housing will continue to be addressed as structural commodities within the SWIS building structure in LRA Table 3.5.2-7, with the Structures Monitoring Program specified for aging management.

Based on its review, the staff found the applicant's response acceptable because the applicant clarified that all applicable system components consisting of discharge fan housings, discharge damper housings, screens (bird screens) for air intake (supply air) and exhaust structures are within the scope of license renewal in accordance with 10 CFR 54.4(a), and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.3.3.29.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HVAC service water intake structure components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC service water intake structure components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.30 HVAC Turbine Building

2.3.3.30.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.30, the applicant described the HVAC turbine building. The HVAC turbine building is designed to provide effective control of airflow throughout the turbine building to maintain all areas at the temperature conditions which provide optimum operation of equipment and comfort and safety of personnel, to limit the spread of contamination during power and shutdown operations of the plant, and to minimize radioactive releases. The system is a recirculating system, designed to operate during startup, normal operation, and shutdown of the plant. The turbine building is maintained at a slight negative pressure by a separate air filtration exhaust system to prevent buildup of radioactivity in the building and to ensure that no unfiltered leakage occurs. The treatment of exhaust air by filters and charcoal absorption filters removes airborne particulates and gaseous radioactivity that might be present before discharging this air to the atmosphere. A separate ventilation system is provided for the reactor recirculation pumps motor generator set room, which maintains the motor generator set room at a higher pressure than the turbine building, thereby, preventing leakage of radioactivity into the room.

The failure of NSR SSCs in the HVAC turbine building could potentially prevent the satisfactory accomplishment of an SR function.

The HVAC turbine building components that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.3.30.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and UFSAR Section 9.4.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) . The staff did not identify any omissions.

2.3.3.30.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HVAC turbine building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC turbine building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.31 HVAC Radwaste Building

2.3.3.31.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.31, the applicant described the HVAC radwaste building. The HVAC radwaste building limits the spread of contamination within the radwaste building, ensuring air movement from clean areas to areas with progressively higher contamination potential. The system also keeps the building at a slight negative static pressure to prevent the exfiltration of potentially radioactive air through other-than-normal exhaust paths connected to the plant stack.

The failure of NSR SSCs in the HVAC radwaste building could potentially prevent the satisfactory accomplishment of an SR function.

The HVAC radwaste building component types that are within the scope of license renewal and subject to an AMR are addressed as civil component/commodities in LRA Section 2.4.

2.3.3.31.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.31 and UFSAR Section 9.4.5 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.3.31.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HVAC radwaste building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HVAC radwaste building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1) . No omissions were identified.

2.3.3.32 Torus Drain System

2.3.3.32.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.32, the applicant described the torus drain system. The torus drain system functions as part of the primary containment pressure boundary, and it supports retention of the suppression pool inventory following postulated fires and SBO events.

The torus drain system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the torus drain system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the torus drain system performs functions that support fire protection and SBO. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-23, the applicant identified the following torus drain system component type that is within the scope of license renewal and subject to an AMR: piping and fittings (misc. auxiliary and drain piping and valves).

2.3.3.32.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.32 and UFSAR Section 6.2 using the evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.32.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the torus drain system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the torus drain system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.33 Civil Structure Auxiliary Systems

2.3.3.33.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.33, the applicant described the civil structure auxiliary systems. Most civil structures have support systems that provide auxiliary services for the structure, such as floor drains, sump pumps, and associated discharge piping and valves. These systems may be within the scope of license renewal because they contain components that perform license renewal intended functions. These systems have been evaluated to identify mechanical or electrical/I&C components that support license renewal intended functions. Applicable components include: (1) primary containment auxiliary system, (2) SW intake structure auxiliary system, (3) reactor building auxiliary system, (4) AOG building auxiliary system, (5) auxiliary boiler house auxiliary system, (6) diesel generator building auxiliary system, (7) control building auxiliary system, and (8) radwaste building auxiliary system.

The civil structure auxiliary systems contain SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the civil structure auxiliary systems could potentially prevent the satisfactory accomplishment of an SR function. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-24, the applicant identified the following civil structure auxiliary systems component types that are within the scope of license renewal and subject to an AMR:

- piping (piping and fittings)
- valves (body and bonnet)
- pump (casing)
- gauge glasses (pressure-retaining housing)

2.3.3.33.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.33 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.3.33 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.33-1, dated April 8, 2005, the staff stated that the civil structure auxiliary systems are not described in the UFASR. The LRA states that civil structure auxiliary systems are within the scope of license renewal. LRA Table 2.3.3 24, which lists component commodity groups requiring an AMR and their intended functions, identifies several components and commodity groups that are within the scope of license renewal; however, no license renewal drawings were provided to determine if the list is complete. Therefore, the staff requested that the applicant provide additional information to allow for a determination that the appropriate civil structure auxiliary systems have been included within the scope of license renewal.

In its response, by letter dated May 4, 2005, the applicant stated that the components noted in the civil/structural auxiliary system consist of miscellaneous equipment database (EDB) entries of a mechanical type without a corresponding system designation or piping and instrument drawing. The civil/structural auxiliary system components identified as within the scope of license renewal provide a mechanical function in support of a structure (e.g., sump pumps for a building). All pressure-retaining mechanical components associated with these civil/structural auxiliary systems were included in LRA Table 2.3.3-24.

Based on its review, the staff found the applicant's response acceptable because a summary of determinations for structure-systems 8020, 8230, 8340, and 8355 can be found in BNP-LR-103 - "Mechanical Screening for Aux. Systems Calculation," and was found to be complete. Therefore, the staff's concern described in RAI 2.3.3.33-1 is resolved.

2.3.3.33.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the civil structure auxiliary systems components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the civil structure auxiliary systems components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.34 Non-Contaminated Water Drainage System

2.3.3.34.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.34, the applicant described the non-contaminated water drainage system (NCWDS). The NCWDS is part of the sewage, sanitary, and roof drains system that collects storm water, non-contaminated drainage, and sanitary wastes, and transports them to collection and processing points for treatment prior to off-site discharge. The overall system is not essential for safe shutdown of the plant and does not satisfy any SR quality criteria; however, the NCWDS has components (roof drain piping) that are within the scope of license renewal because of potential spatial interactions with SR components. These components have been included within the scope of license renewal as a result of the 10 CFR 54.4(a)(2) review.

The failure of NSR SSCs in the NCWDS could potentially prevent the satisfactory accomplishment of an SR function. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.3-25, the applicant identified piping (piping and fittings) as the NCWDS component type that is within the scope of license renewal and subject to an AMR.

2.3.3.34.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and USFAR Section 9.3.3.2.3 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.3.34.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the NCWDS components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the NCWDS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

In LRA Section 2.3.4, the applicant identified the structures and components of the steam and power conversion systems that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the steam and power conversion systems in the following sections of the LRA:

- 2.3.4.1 main steam system
- 2.3.4.2 extraction steam system
- 2.3.4.3 moisture separator reheater drains system and reheat steam system
- 2.3.4.4 auxiliary boiler
- 2.3.4.5 feedwater system
- 2.3.4.6 heater drains and miscellaneous vents and drains
- 2.3.4.7 condensate system
- 2.3.4.8 turbine building sampling system
- 2.3.4.9 main condenser gas removal system

- 2.3.4.10 turbine electro-hydraulic control system
- 2.3.4.11 turbine generator lube oil system
- 2.3.4.12 stator cooling system
- 2.3.4.13 hydrogen seal oil system

The corresponding subsections of this SER (2.3.4.1 – 2.3.4.13, respectively) present the staff's review findings with respect to the steam and power conversion systems for Units 1 and 2.

2.3.4.1 Main Steam System

2.3.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.1, the applicant described the main steam (MS) system. The MS system delivers steam from the nuclear steam supply system (NSSS) piping downstream of the outermost primary containment isolation valve to the turbine throttle over the full range of reactor power operation. This system also conveys steam to the second stage reheaters, condenser steam-jet air ejectors, turbine steam seal regulators, main turbine bypass, and reactor feed pump drive turbines. The turbine stop and control valves, control isolation valves, turbine bypass valves, and associated hydraulic operators (hydraulic fluid supplied by the electro-hydraulic control (EHC) system) are included in this system. There are four main steam lines conveying steam to the turbine stop valves, with cross connections to the turbine bypass system and other equipment as required. This system interfaces with the RCPB (but is not part of the RCPB) and does not penetrate the primary containment.

The failure of NSR SSCs in the MS system could potentially prevent the satisfactory accomplishment of an SR function. The MS system also performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides post-accident containment, holdup, and plateout of MSIV bypass leakage

In LRA Table 2.3.4-1, the applicant identified the following MS system component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings [steam lines to main turbine (Group B)]
- piping and fittings (steam drains)
- valves (check, control, hand, motor operated, safety valves) (body and bonnet)

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 and UFSAR Section 10.3.2 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.1.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the MS system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the MS system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.2 Extraction Steam System

2.3.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.2, the applicant described the extraction steam system. The extraction steam system provides steam heating to two strings (A and B) of five feedwater heaters which progressively increase the feedwater temperature before it enters the reactor. The system also provides steam to the heater drains deaerator to remove non-condensable gases from the condensate. This system consists of the piping and valves that extract steam from selected stages of the high pressure (HP) and low pressure (LP) turbines and supply the steam to the shell side of the feedwater heaters. Non-return valves are used to prevent overspeed of the turbine due to flashback of the condensate in the heaters after a turbine trip.

The failure of NSR SSCs in the extraction steam system could potentially prevent the satisfactory accomplishment of an SR function. The extraction steam system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in Section 2.4.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 and USFAR Section 10.3.2 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.2.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the extraction steam system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the extraction steam system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.3 Moisture Separator Reheater Drains System and Reheat Steam System

2.3.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.3, the applicant described the moisture separator reheater (MSR) drains system and reheat steam system. The MSR drains system and reheat steam system returns large quantities of saturated water, removed in the moisture separator and condensed from the reheat steam system in the first and second stage reheater tubes, to the condensate cycle to improve cycle efficiency, operating stability, and reliability. System components include moisture separator drain tanks, first-stage reheater drain tanks, second-stage reheater drain tanks, and the valves and piping necessary to remove liquid from the MSRs and direct it to the condensate system for reuse.

The failure of NSR SSCs in the MSR drains system and reheat steam system could potentially prevent the satisfactory accomplishment of an SR function.

The MSR drains system and reheat steam system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 and UFSAR Section 10.2.2 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.3.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an

AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the MSR drains system and reheat steam system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the MSR drains system and reheat steam system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.4 Auxiliary Boiler

2.3.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.4, the applicant described the auxiliary boiler. The auxiliary boiler system provides a source of non-contaminated steam independent of the NSSS. This is a unit-shared system providing: (1) steam for operation of the CAC vaporizer and (2) steam to Unit 1 and 2 for HPCI, RCIC, and reactor feed pump turbine testing prior to start up. Auxiliary steam is supplied by one packaged, fire tube boiler and distributed to the plant via a network of headers and piping. This system consists of the auxiliary boiler and the following principal subsystems: fuel oil, combustion air, burner control, exhaust, feedwater, chemical addition, blowdown, and deaerator.

The failure of NSR SSCs in the auxiliary boiler could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.4-2, the applicant identified the following auxiliary boiler component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (steam drains)
- valves (check, control, hand, motor operated, safety valves) (body and bonnet)

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 and UFSAR Section 10.4.8 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.4.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the auxiliary boiler components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the auxiliary boiler components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.5 Feedwater System

2.3.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.5, the applicant described the feedwater (FW) system. The FW system receives demineralized water from the condensate system and delivers this water to the reactor at increased temperature and pressure. Condensate is pumped from the condenser hotwell through the three LP heaters to the common suction header for the two, 50 percent capacity, turbine-driven reactor feed pumps. FW heaters receive shell-side steam and preheat the tube-side feedwater, thus increasing the heat cycle efficiency. All FW heaters and drain coolers are included in the FW system, and this system ends at the interfacing system SR outermost primary containment isolation valves.

The FW system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the FW system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the FW system performs functions that support fire protection and SBO. The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.4-3, the applicant identified the following FW system component types that are within the scope of license renewal and subject to an AMR:

- main feedwater line (pipe and fittings (Group B or D))
- valves (control, check, and hand valves) (body and bonnet)

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5 and UFSAR Section 10.4.7 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff’s review of LRA Section 2.3.4.5 identified an area in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The applicant responded to the staff’s RAI as discussed below.

In RAI 2.3.4.5-1, dated April 8, 2005, the staff stated that license renewal drawing D-25021-LR, sheet 1C, locations B-7 and C-7, and drawing D-02521 LR, sheet 1C, locations B-8 and C-8, have LRA flags in the middle of a section of pipe. Therefore, the staff requested that the applicant explain how the LRA boundary can occur in the middle of a section of pipe.

In its response, by letter dated May 4, 2005, the applicant stated:

> Failure of the referenced portion of the non-safety related feedwater system lines, shown on drawing D-25021-LR, sheet 1C, locations B-7 and C-7, and drawing D-02521-LR, sheet 1C, locations B-8 and C-8, have been evaluated. The evaluation was performed as part of the stress analysis of the interface between the non-safety related feedwater system piping boundary shown with the license renewal flag and the piping boundary at the safety related F032A/B outside containment isolation valves which are part of the reactor vessel and internals system. The intended function of M-1 was conservatively chosen for this portion of the feedwater system piping. The license renewal boundary flag is shown correctly on drawings D-25021-LR, sheet 1C, and D-02521-LR, sheet 1C.
>
> The subject Unit 1 and Unit 2 non-safety related feedwater piping is in scope since it is seismically analyzed, connected to safety related reactor vessel and internals system components, and could have spatial interactions with safety related components. Failure of feedwater piping outside the license renewal boundary flag has been evaluated and will not affect the safety related intended function of reactor vessel and internals system components. The BSEP scoping methodology included piping as in-scope where piping failure could affect nearby safety related components through spray, falling down, or being seismically connected. The subject in-scope feedwater piping is seismically connected but is also located in the reactor building and, therefore, cannot be allowed to spray or fall on safety related components in the reactor building. The intended function of M-1 for the subject in-scope feedwater system piping was conservatively chosen to provide an aging management program for both the piping internal and external surface. ISG-9 recommends that if the in-scope connected non-safety related component is of a similar material/environment combination, a similar aging management program should be applied for the connected safety related component. For the subject piping, similar aging management programs were chosen as those of the connected safety related reactor vessel and internals system components. In summary, the license renewal boundary flag is shown correctly on D-25021-LR, Sheet 1C, and D-02521-LR, sheet 1C, with a pressure boundary mechanical intended function.

Based on its review, the staff found the applicant's response to RAI 2.3.4.5-1 acceptable because the subject portions of the feedwater system lines are non-safety related, and the applicant performed analysis to demonstrate that the failure of these subject portions of the feedwater system lines would not have spatial interactions with safety related components. Therefore, the staff’s concern described in RAI 2.3.4.5-1 is resolved.

2.3.4.5.3 Conclusion

The staff reviewed the LRA, the accompanying scoping boundary drawings, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the FW system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the FW system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.6 Heater Drains and Miscellaneous Vents and Drains

2.3.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.6, the applicant described the heater drains and miscellaneous vents and drains systems. The heater drains (HD) system is a cascading drain system. Extraction steam enters the heater shell side, gives up its energy to the condensate/feedwater passing through the tubes and is gravity-drained to the next lower pressure heater. This system maintains the feedwater heaters and deaerator level, removes non-condensable gases from the feedwater heaters, supplies heating steam to the Number 3 feedwater heaters, and recovers the steam used for heating in the feedwater heaters. The miscellaneous vents and drains (MVD) system provides equipment drainage and vent paths to collection locations, including the main condenser. MVD piping includes drains from the main steam system, miscellaneous condensate header, turbine building area equipment, the HPCI steam supply drain pot, and the RCIC steam supply drain pot.

The failure of NSR SSCs in the HD and MVD systems could potentially prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides structural support/seismic integrity
- provides post-accident containment, holdup, and plateout of MSIV bypass leakage

In LRA Table 2.3.4-4, the applicant identified the following HD and MVD systems component types that are within the scope of license renewal and subject to an AMR:

- piping and fittings (lines to feedwater heaters)
- piping and fittings (steam drains)
- valves (body and bonnet)

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6 and UFSAR Section 10.4.7.2.5 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.6.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the HD and MVD systems components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the HD and MVD systems components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.7 Condensate System

2.3.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.7, the applicant described the condensate system. Condensate originates in the main condenser hotwells and comes primarily from exhaust steam exiting the main turbine and the reactor feed pump turbines. The condensate pumps take suction from the hotwells, pump the condensate forward through the tube side of several equipment condensers, and maintain balanced condensate flow to the feedwater heaters. Downstream, the condensate is processed through the condensate filter demineralizers to condensate deep-bed demineralizers (CDDs), and the condensate booster pumps. BSEP Units 1 and 2 are each equipped with a 500,000 gallon capacity condensate storage tank (CST) providing suction to condensate transfer pumps, makeup water to the main condenser hotwells, alternate suction source to the CS and CRD hydraulic systems, and normal suction source to the RCIC and HPCI systems. The main condenser provides a heat sink for the turbine exhaust steam, turbine bypass steam, and reactor feed pump turbine exhaust steam, and it is cooled by the circulating water system. The main condenser is credited in alternative source term analyses.

The condensate system contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the condensate system could potentially prevent the satisfactory accomplishment of an SR function. In addition, the condensate system performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides post-accident containment, holdup, and plateout of MSIV bypass leakage

In LRA Table 2.3.4-5, the applicant identified the following condensate system component types that are within the scope of license renewal and subject to an AMR:

- condensate lines (piping and fittings)
- valves (body and bonnet)
- condensate storage (tank)
- condensate cleanup system (piping and fittings)
- condensate lines (piping and fittings)
- valves (body and bonnet)
- condensate coolers/condensers (tubes)
- condensate coolers/condensers (tubesheet)
- condensate coolers/condensers (shell)

2.3.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.7 and UFSAR Sections 3.4.2.6, 9.2.6, and 10.4.2 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.4.7 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.4.7-1, dated April 8, 2005, the staff stated that UFSAR Section 3.4.2.6 states that various flood-level alarms in the circulation water condenser pits warn the operator that an abnormal condition exists and that water is entering the pit. The UFSAR further states that a set of three level alarms installed 9 feet above the pit floor will, when activated, automatically shut off the circulating water pumps. In light of the fact that the main condenser will not be designated to serve as a pressure-retaining boundary for license renewal, the staff requested that the applicant provide additional information to address whether any SR equipment or equipment that supports a safety function could be affected by flooding in this area.

In its response, by letter dated May 4, 2005, the applicant stated that a review of flood susceptibility noted that the failure of the expansion joints in the circulating water condenser pits had the potential to result in the automatic shutdown of both reactors, and NSR leak detection equipment was installed in the condenser pits to address this concern. The applicant also stated that while such a failure might represent a challenge to SR equipment, it would not impair any SR function and is not the basis for including SSCs in the scope of license renewal.

The staff found the applicant's response acceptable because flooding of this area would be addressed by the existing leak detection equipment and because a flood in this area would not impair any SR function. Therefore, the staff's concern described in RAI 2.3.4.7-1 is resolved.

Also, as stated in RAI 2.3.4.7-1, the main condenser will not be designated to serve as a pressure-retaining boundary for license renewal. This is an intended revision to the M-1 designation given to it in LRA Table 2.3.4-5. The main condenser will however retain the M-7 designation of "Provide post-accident containment, holdup, and plateout of MSIV bypass leakage." It is the applicant's intention to revise LRA Table 2.3.4-5 accordingly. The staff discussed this issue with the applicant during a March 2005 site visit. The applicant stated that the main condenser is not needed to perform any function post-accident that would require it to retain pressure. The main condenser in fact operates at a slight vacuum during normal operation. The applicant stated that integrity of the main condenser is continuously monitored during normal operation and that loss of vacuum would cause a plant shut down. The applicant stated that the M-7 designation is placed on the main condenser due to application of the alternative source term.

The staff found the deletion of the M-1 designation to be acceptable because there is no post-accident function of the main condenser which requires that it be capable of serving as a pressure-retaining boundary and because the integrity of the main condenser is continuously monitored during normal operation for its ability to operate sub-atmospheric.

2.3.4.7.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the condensate system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the condensate system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.8 Turbine Building Sampling System

2.3.4.8.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.8, the applicant described the turbine building sampling system. In the turbine building, there is a central sample station, essentially a package of sample conditioning and analyzing sections and a sample hood. Samples can be taken continuously or obtained as grab samples for laboratory analysis and consist of three basic types: liquid sampling, steam sampling, and gaseous sampling. Grab samples are taken at the hood, which is designed for constant recovery and splashless withdrawal. The purpose of plant process sampling is to monitor the plant and equipment performance and to determine routine chemical properties and radiation levels necessary to provide information for equipment operation, corrosion control, and radiation activity. The system is not required either for safe shutdown or following an accident and is, therefore, not classified as an essential system. A small amount of tubing in the turbine building sampling system is credited in alternative source term analyses for mitigation of radioactive releases following postulated accidents.

The failure of NSR SSCs in the turbine building sampling system could potentially prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides a pressure-retaining boundary/flow
- provides post-accident containment, holdup, and plateout of MSIV bypass leakage

In LRA Table 2.3.4.8, the applicant identified the following turbine building sampling system component types that are within the scope of license renewal and subject to an AMR: piping and fittings (steam drains).

2.3.4.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6 and UFSAR Section 9.3.2 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.8.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the turbine building sampling system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the turbine building sampling system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.9 Main Condenser Gas Removal System

2.3.4.9.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.9, the applicant described the main condenser gas removal system. During normal plant operation, non-condensable gases are produced and entrained in the reactor steam cycle and must be continuously removed to maintain turbine efficiency. These gases include hydrogen and oxygen from the radiolytic decomposition of water, fission products, activation products, and air from condenser in-leakage. The mixture is drawn from the main condenser via the steam jet air ejectors (SJAEs). Motive force for the SJAE flow is provided by steam taken off the HP steam supply to the reactor feedwater pump turbines. Two mechanical vacuum pumps are used primarily during startup when there is insufficient reactor steam to operate the SJAE to maintain a condenser vacuum. The steam and non-condensable mixture that exits the SJAE is mixed with oxygen injected from the hydrogen water chemistry system. This is done to insure sufficient oxygen is available for scavenging all free hydrogen in the offgas mixture during the recombination process. The mixture is then passed through an offgas recombiner where hydrogen and oxygen are catalytically recombined to form water. After recombination, the off-gas is routed to a condenser to remove moisture and then through a 30-minute delay pipe before entering the AOG charcoal adsorber system.

The failure of NSR SSCs in the main condenser gas removal system could potentially prevent the satisfactory accomplishment of an SR function. The main condenser gas removal system also performs functions that support fire protection and SBO.

The intended function, within the scope of license renewal, is to provide a pressure-retaining boundary/flow.

In LRA Table 2.3.4-7, the applicant identified the following main condenser gas removal system component types that are within the scope of license renewal and subject to an AMR:

- condensate lines (piping and fittings)
- valves (body and bonnet)

2.3.4.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.9 and UFSAR Section 10.4.2 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.9.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the main condenser gas removal system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the main condenser gas removal system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.10 Turbine Electro-Hydraulic Control System

2.3.4.10.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.10, the applicant described the turbine EHC system. The turbine EHC system maintains a fixed load or speed of the turbine, depending on requirements, and provides turbine overspeed protection in the event of excessive unbalanced energy input to the turbine shaft. The objective of the system is to provide an energy control system that coordinates turbine generator load and reactor output power. The system operates the turbine stop valves, bypass valves, control valves, combined intermediate valves, and other protective devices and provides for mechanical and electrical trips of the turbine. The turbine pressure regulator manipulates turbine control valves and turbine bypass valves, individually or in parallel, to maintain constant reactor pressure at a chosen value. The turbine controls combine standard solid-state electronic operational amplifier elements with HP hydraulic actuators to produce a quick response speed-load control system. The turbine EHC system supplies clean, cool, HP hydraulic fluid necessary for turbine valve operation. The system uses a pump that takes suction on a hydraulic reservoir to supply all components requiring EHC fluid for operation.

The failure of NSR SSCs in the turbine EHC system could potentially prevent the satisfactory accomplishment of an SR function.

The turbine EHC system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.4.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6 and UFSAR Section 10.2.2 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.10.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the turbine EHC system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the turbine EHC system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.11 Turbine Generator Lube Oil System

2.3.4.11.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.11, the applicant described the turbine generator lube oil (LO) system. The turbine generator LO system provides a reliable, continuous supply of clean, cool oil to the turbine generator bearings, hydrogen sealing system, and turbine instrumentation during all modes of operation. System equipment includes oil coolers, pumps, strainers, filters and piping.

The failure of NSR SSCs in the turbine generator LO system could potentially prevent the satisfactory accomplishment of an SR function.

The turbine generator LO system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.4.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.11 and UFSAR Section 10.2.2 and 10.2.4 using the Tier-2 evaluation methodology described in SER Section 2.3. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.3.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.3.4.11 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.4.11-1, dated April 8, 2005, the staff stated that LRA section 2.3.4.11 states that the turbine generator LO system is within the scope of license renewal because it contains components which are NSR whose failure could prevent satisfactory accomplishment of SR functions. Previous BWR applicants have identified the following component groups and their intended functions within the turbine generator LO system as being within the scope of license renewal and subject to an AMR:

- closure bolting (pressure boundary)
- filters/strainers (spatial interaction)
- piping and fittings (spatial interaction)
- piping and fittings (structural integrity/attached support)
- pump casings (spatial interaction)

- tanks (spatial interaction)
- valves (spatial interaction)
- valves (structural integrity/attached support)

LRA section 2.3.4.11 states that the turbine generator LO system components that are subject to AMR are addressed as civil commodities in LRA Section 2.4 with no clarifying information provided. Therefore, the staff requested that the applicant provide additional information to confirm that all turbine generator LO system components within the scope of license renewal and subject to an AMR have been identified.

In its response, by letter dated May 4, 2005, the applicant stated that the turbine generator LO system supplies lubricating oil for proper operation of the main turbine; however, operation of the main turbine is not necessary to support any intended function for license renewal. The applicant stated that the entire turbine generator LO system is NSR; however, there are selected active electrical switches that must be seismically analyzed to prevent undesirable interactions with SR equipment and that the supports for components having this quality classification are within the scope of license renewal as civil commodities and are identified as an electrical enclosure commodity listed in LRA Table 2.4.2-10. The applicant also stated that the review conducted at BSEP pursuant to 10 CFR 54.4(a)(2) determined that the pressure boundary components and commodities of the turbine generator LO system are not within the scope of license renewal either for potential spatial interactions with in-scope equipment or for providing support for the seismically analyzed portions of systems within the scope of license renewal.

The staff found the applicant's response acceptable because the BSEP turbine generator LO system is NSR and does not perform an intended function within the meaning of the 10 CFR 54.4(a) criteria. Therefore, the staff's concerns described in RAI 2.3.4.11-1 are resolved.

2.3.4.11.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the turbine generator LO system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the turbine generator LO system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.12 Stator Cooling System

2.3.4.12.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.12, the applicant described the stator cooling system. The stator cooling system automatically regulates the temperature and flow of clean, low conductivity water to cool the main generator stator windings and the power rectifiers of the generator exciter. The cooling water is in direct contact with the stator windings which enhance the heat transfer rate from the copper windings and enable the generator to assume varying loads while eliminating most of the thermal stresses induced in the winding insulation. The system consists of a closed cooling loop that is, in turn, cooled by the TBCCW system. The scope of this system includes the stator leak monitoring system (SLMS). The SLMS monitors the leakage of hydrogen into the stator cooling water. Additionally, the SLMS provides for the proper oxygenation of the stator cooling water to promote the formation of cupric oxide, a tough and durable coating, on the stator bar internal surfaces.

The failure of NSR SSCs in the stator cooling system could potentially prevent the satisfactory accomplishment of an SR function.

The stator cooling system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.12 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.12.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the stator cooling system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the stator cooling system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.13 Hydrogen Seal Oil System

2.3.4.13.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.13, the applicant described the hydrogen seal oil system. The hydrogen seal oil system supplies sealing oil to the generator shaft seal rings to prevent the escape of hydrogen from the generator casing. The seal oil, supplied from the turbine main bearing oil header, is vacuum-treated to remove air and moisture, and boosted in pressure above that of the hydrogen pressure in the generator casing. NSR components in the system have been classified as seismically analyzed to avoid adverse interactions with SR SSCs during an earthquake.

The failure of NSR SSCs in the hydrogen seal oil system could potentially prevent the satisfactory accomplishment of an SR function.

The hydrogen seal oil system component types that are within the scope of license renewal and subject to an AMR are addressed as civil commodities in LRA Section 2.4.

2.3.4.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.13 using the Tier-1 evaluation methodology described in SER Section 2.3.

In conducting its Tier-1 review of the two-tier review process, the staff evaluated the system functions described in the LRA in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.4.13.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the hydrogen seal oil system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the hydrogen seal oil system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results – Structures

This section documents the staff’s review of the applicant’s scoping and screening results for structures. Specifically, this section discusses the following structures:

- containment
- other Class 1 and in-scope structures

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived mechanical SSCs that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that there are no omissions of structures and components that meet the scoping criteria and are subject to an AMR.

Staff Evaluation Methodology. The staff’s evaluation of the information provided in the LRA was performed in the same manner for all structures. The objective of the review was to determine if the components and supporting structures for a specific structure, that appeared to meet the scoping criteria specified in the Rule, were identified by the applicant as within the scope of license renewal, in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Scoping. To perform its evaluation, the staff reviewed the applicable LRA section and associated component drawings, focusing its review on components that had not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each structure and component to determine if the applicant had omitted components with intended functions delineated under 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the licensing basis documents to determine if all intended functions delineated under 10 CFR 54.4(a) were specified in the LRA. If omissions were identified, the staff requested additional information to resolve the discrepancies.

Screening. Once the staff completed its review of the scoping results, the staff evaluated the applicant's screening results. For those structures and components with intended functions, the staff sought to determine (1) if the functions are performed with moving parts or a change in configuration or properties, or (2) if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that did not meet either of these criteria, the staff sought to confirm that these structures and components were subject to an AMR as required by 10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

2.4.1 Containment

2.4.1.1 Primary Containment

2.4.1.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1.1, the applicant described the primary containment. The primary containment for each BSEP unit is a pressure suppression system consisting of a drywell and a pressure suppression chamber. The drywell houses the reactor vessel, the reactor coolant recirculation loops, and other branch connections of the RCS. In the event of a process system piping failure, reactor water and steam will be released into the drywell atmosphere. The resulting increased drywell pressure will then force a mixture of drywell atmosphere, steam, and water through the vents which open beneath the surface of the pool of water stored in the suppression chamber. The steam will condense in the water resulting in a rapid pressure reduction in the drywell. The primary containment is designed to contain the energy released during the design-basis LOCA and to limit the fission products associated with this accident that are released to the reactor building (secondary containment). Primary containment is classified as a seismic Class 1 structure and must remain functional and protect vital equipment and systems both during and following the most severe natural phenomenon postulated to occur at the site. The primary containment is a BWR Mark 1 design located in the reactor building of each BSEP unit. Unlike other BWRs which employ a Mark 1 containment fabricated of steel, the primary containment is constructed of reinforced concrete with a steel liner. The major structural components of the primary containment are the drywell, sacrificial shield, reactor pedestal, suppression chamber (also called the torus or wetwell), and a connecting venting system.

The primary containment contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the primary containment could potentially prevent the satisfactory accomplishment of an SR function. In addition, the primary containment performs functions that support fire protection, EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides pressure boundary and/or fission product barrier
- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides source of cooling water for plant shutdown
- provides missile barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provides pipe whip restraint and/or jet impingement protection
- provides heat sink during SBO or DBAs
- provides spray shield or curbs for directing flow

In LRA Table 2.4.1-1, the applicant identified the following primary containment component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument support, etc.)
- bellows (refueling)
- cable tray and conduit
- concrete above grade
- sacrificial shield wall
- concrete curbs
- doors and framing/hardware
- downcomers (open-ended pipes attached to torus vent header)
- drywell head
- drywell liner
- electrical enclosure
- electrical support

- equipment support
- floor drains
- HVAC support
- instrument support
- insulation
- liner (sump)
- moisture barrier
- penetration (mechanical and electrical)
- drywell personnel airlock, equipment hatch, CRD hatch
- pipe support
- reactor pressure vessel support
- seals and gaskets (manways, airlocks, doors, hatches)
- side bearing plate
- structural steel: platforms strairways, mezzanines and hardware
- torus liner
- vent header (drywell to torus vent lines and ring header)
- vent line bellows
- whip restraints (includes jet impingement shields)

2.4.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1.1 and UFSAR Sections 3.8 and 6.2.1 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4, "Scoping and Screening Results - Structures."

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.4.1.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.4-1, dated April 25, 2005, the staff noted that BSEP primary containment encloses the reactor vessel and a number of other structures, such as the concrete pedestal and seismic bracing for the drywell. LRA Table 2.4.1-1 does not indicate that these structures are within the scope of license renewal. These structures perform SR functions; therefore, the staff requested that the applicant address the following: (1) if the structures are not included through an oversight, the staff requested that the applicant provide a description of their scope and AMR; (2) if they are covered somewhere else in the LRA, the staff requested that the applicant provide the relevant information; and (3) if they are excluded from within the scope of license renewal, the staff requested that the applicant provide the basis for excluding these items from the scope of license renewal.

In its response, by letter dated May 11, 2005, the applicant indicated that the concrete pedestal is within the scope of license renewal and is addressed within the "Concrete Above Grade" commodity group. Seismic stabilizers utilized between the RPV and the biological shield wall are within the scope of license renewal, and are addressed within the "RPV Support" commodity group. Seismic ties utilized between the biological shield wall and the drywell wall are within the scope of license renewal, and are addressed within the "Structural Steel" commodity group.

Based on the inclusion of the structures, identified in the RAIs, as part of the commodity group considered in LRA Table 2.4.1.1, the staff’s concern described in RAI 2.4-1 is resolved.

In RAI 2.4-2, dated April 25, 2005, the staff noted that in the information provided in LRA Section 2.4.1, it was not clear whether all drywell and torus supports are within the scope of license renewal. The staff stated that (1) if the drywell and torus supports were not included as an oversight, the staff requested that the applicant provide a description of their scope and aging management review; (2) if they were covered somewhere else in the LRA, the staff requested that the applicant indicate the location; and (3) if they were excluded from within the scope of license renewal, the staff requested that the applicant provide the basis for excluding these items from within the scope of license renewal.

In its response, by letter dated May 11, 2005, the applicant stated that all drywell and torus supports are within the scope of license renewal. The subject supports are addressed within a variety of commodity groups such as: "Electrical Support," "Equipment Support," "HVAC Support," "Instrument Support," "Pipe Support," "Structural Steel," and "Whip Restraints," as shown in LRA Table 2.4.1-1. Although pipe supports are identified by a single commodity group in LRA Table 2.4.1-1, they are sub-categorized by American Society of Mechanical Engineers (ASME) Code Class designation, as shown in LRA Table 3.5.2-1. The structural components identified in the RAI are included as part of various commodity groups; therefore, the staff’s concern described in RAI 2.4-2 is resolved.

2.4.1.1.3 Conclusion

The staff reviewed the LRA, and RAI responses to determine whether any structure and structural components that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the primary containment components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the primary containment components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Other Class 1 and In-Scope Structures

In LRA Section 2.4.2, the applicant identified the structures and components of the other Class 1 and in-scope structures that are subject to an AMR for license renewal.

The applicant described the supporting structures and components of the other Class 1 and in-scope structures in the following sections of the LRA:

- 2.4.2.1 intake and discharge canals
- 2.4.2.2 refueling system
- 2.4.2.3 switchyard and transformer yard structures
- 2.4.2.4 monorail hoists
- 2.4.2.5 bridge cranes
- 2.4.2.6 gantry cranes
- 2.4.2.7 service water intake structure
- 2.4.2.8 reactor building
- 2.4.2.9 augmented off-gas building
- 2.4.2.10 diesel generator building
- 2.4.2.11 control building
- 2.4.2.12 turbine building
- 2.4.2.13 radwaste building
- 2.4.2.14 water treatment building
- 2.4.2.15 miscellaneous structures and out-buildings

The corresponding subsections of this SER (2.4.2.1 – 2.4.2.15, respectively) present the staff's review findings with respect to the other Class 1 and in-scope structures for Units 1 and 2.

Staff Evaluation. The staff reviewed LRA Sections 2.4.2.1 through 2.4.2.15, and related UFSAR sections using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Sections 2.4.2.1 through 2.4.2.15 and identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. In addition to the review results discussed in the specific sections of this SER, the following paragraphs summarize staff review findings that cover multiple component groups.

In RAI 2.4-4, dated April 25, 2005, the staff stated that as a result of its review of LRA Section 2.4, "Scoping and Screening Results - Structures," and LRA Figure 2.2-1, the staff found that some structures are not considered within the scope of license renewal. These structures include the circulating water intake structure, chlorination building, auxiliary boiler house, auxiliary surge tank, diesel generator fuel oil tank vault, radioactive material container storage, and service building. The staff questioned whether all these structures serve no intended function as defined in 10 CFR 54.4(a)(1); therefore, the staff requested that the applicant provide a detailed description of these structures (including their function), and describe the technical bases for their exclusion from the scope of license renewal. Also, the staff requested that the applicant verify that none of these structures serves a seismic II/I intended function as defined in 10 CFR 54.4(a)(2).

In its supplemental response, by letter dated July 18, 2005, the applicant provided a description (including structural function) for each of the above mentioned structures and stated that the determination whether a structure is within the scope of license renewal is based on the information provided in the UFSAR, DBD, EDB, Maintenance Rule database, and license renewal scoping evaluations. As such, if a structure contains any components within the scope of license renewal or if the structure supports a license renewal intended function, this structure is considered within the scope of license renewal. Those structures that contain no license renewal components and support no license renewal intended functions are outside the scope of license renewal. The applicant's justification and basis for excluding these structures from the license renewal scope are discussed below:

Circulating Water Intake Structure. The circulating water intake structure, as stated in the UFSAR, is located a sufficient distance from SR structures such that any failure of this structure during a hurricane or tornado will not affect those SR structures. In addition, this structure is classified as an NSR structure in the EDB, and does not contain any components that are within the scope of license renewal nor does it support a license renewal intended function. Therefore, this building is not within the scope of license renewal.

Chlorination Building. The chlorination building is an unclassified sheet metal structure attached to the south side of the service water intake structure which is a Class I reinforced concrete structure designed for seismic, tornado, and hurricane loads. The chlorination building does not contain any components that are within the scope of license renewal, nor does it support a license renewal intended function. Based on the lightweight design of the chlorination building compared to the robust design of the service water intake structure, any loading due to failure of the chlorination building on the service water intake structure would be enveloped by the Class I design criteria. As such, the chlorination building is not a seismic II/I risk for the service water intake structure. Therefore, this building is not within the scope of license renewal.

Auxiliary Boiler House. The auxiliary boiler house (a steel frame structure with a reinforced concrete foundation mat and insulated metal sidings and built-up roofing) is located a sufficient distance from all Class I structures. This building is an non-classified structure. SSCs within the building do not support any license renewal intended functions based on review of the EDB safety classifications. This structure is not within the scope of license renewal.

Auxiliary Surge Tank. The auxiliary surge tank (a stainless steel tank mounted on a concrete foundation) is located east of the Unit 2 reactor building and is not directly adjacent to any Class I structure. This tank contains radioactive wastes in excess of normal operational quantities. Radioactive levels within this tank are procedurally controlled to a limit of less than

10 curies in accordance with Technical Specification (TS) Section 5.5.8; as such, the failure of this tank would not exceed limits associated with 10 CFR 54.4(a)(1)(iii). Therefore, the auxiliary surge tank, tank foundations and supports do not support license renewal intended function and are outside the scope of license renewal.

Diesel Generator Oil Tank Vault. The diesel generator oil tank vault is a reinforced concrete building for housing the underground diesel fuel storage tank, and is located to the east of the diesel generator building. Although it is not listed in LRA Table 2.4.2-9, "Component Commodity Groups Requiring Aging Management Review and Their Intended Functions: Diesel Generator Building," this tank building is considered as part of the diesel generator building, and is within the scope of license renewal.

Radioactive Material Container Storage Building. The radioactive material container storage building is located north of the Unit 1 turbine and reactor buildings, and is not adjacent to any Class I structure. This building does not contain any components that are within the scope of license renewal, and does not support any license renewal intended function. Therefore, it is not within the scope of license renewal.

Service Building. The service building (a steel frame structure with insulated metal siding and roof panels) is not adjacent to any Class I structure, and does not support any SR functions. Also, this building does not contain any components that are within the scope of license renewal, nor does it support a license renewal intended function. Therefore, this building is not within the scope of license renewal.

The staff reviewed the applicant's response and found that it provides an adequate technical basis for the scoping determination. On the basis of the above discussion, the staff's concerns described in RAI 2.4-4 are resolved.

In RAI 2.4-8, dated April 25, 2005, the staff stated that in review of LRA Tables 2.4.2-1 through 2.4.2-14, it found that some of these tables indicate that structural steel includes platforms, stairways, mezzanines, and hardware. It was not clear to the staff whether the term "structural steel" covers major structural components, such as beams, columns, and roof frames. Therefore, the staff requested that the applicant respond to the following questions: (1) what is covered under the word "hardware," (2) which structural steel components are considered "hardware," (3) are the major structural steel components (e.g., beams, columns, roof frames, other steel frames, etc.) considered hardware, and (4) if not, in which table (or tables) are these structural components listed for the AMR?

In its letter responses, dated May 11, 2005 and June 21, 2005, the applicant clarified that the term "hardware" is associated with connection components, such as, nuts, bolts, washers, etc. The applicant noted that major structural steel components, such as, beams, columns, roof frames, and other steel frames were not listed specifically in the summary tables of aging management evaluation; however, these steel components were considered to be structural steel components and were addressed within the "Structural Steel" commodity group. The staff considered the applicant's response reasonable and acceptable. Therefore, the staff's concern described in RAI 2.4-8 is resolved.

In RAI 2.4-10, dated April 25. 2005, the staff stated that LRA Section 2.4 identifies that masonry walls located in the service water intake structure, reactor building, augmented off-gas building, diesel generator building, control building, and turbine building are within the scope of license renewal. Therefore, the staff requested that the applicant identify whether there are masonry walls located in other in-scope building structures, such as the radwaste building, water treatment building, HPCI CO_2 bottle storage building, etc. If there are masonry walls located in these buildings, the applicant was also requested to include these masonry walls in the component commodity groups requiring AMR or provide justification for their exclusion from within the scope of license renewal.

In its response, by letter dated May 11, 2005, the applicant clarified that there are no masonry walls in the HPCI CO_2 bottle storage building. The masonry wall located in the water treatment building is used as a fire protection impingement barrier between the diesel fire pump and the fuel oil tank, and it is within the scope of license renewal. There are masonry walls located in the radwaste building; however, these walls do not support any license renewal intended function (including the II/I issue) and, therefore, have been screened out from license renewal. The staff found that the license's clarification is sufficient; therefore, the staff's concerns described in RAI 2.4-10 are resolved.

In RAI 2.4-11, dated April 25, 2005, regarding the scoping and screening of the crane/rail systems, the staff requested that the applicant clarify the treatment of cranes and hoists in the scoping and screening, and in the AMR. In addition, the staff requested that the applicant provide the following information:

(qqqqqqqqq) A list of all cranes/hoists/rails and associated components in the scope of license renewal.

(rrrrrrrrr) A list of all cranes/hoists/rails and associated components requiring an AMR (i.e., passive, long-lived).

(sssssssss) A list of all cranes/hoists/rails and associated components requiring aging management and/or TLAA.

In its response, by letter dated May 11, 2005, the applicant provided its scoping and screening results of cranes systems (monorail hoists, bridge cranes, gantry cranes, etc,) as follows:

> The Units 1 and 2 refueling platforms are considered cranes within the scope of license renewal. Monorail hoists are categorized as "Structural Steel" for the purpose of license renewal and are managed by the Structures Monitoring Program.

The applicant also stated that the commodity groups of bridge cranes and gantry crane are within the scope of license renewal. There are nine bridge cranes and two gantry cranes in the BSEP nuclear plant (Units 1 and 2): Units 1 and 2 reactor building bridge cranes, Units 1 and 2 turbine building bridge cranes, Unit 1 jib crane, four diesel generator bridge cranes, intake structure gantry crane, and the heater bay gantry crane. As a result of the screening process, only the reactor building bridge cranes, Unit 1 jib crane, diesel generator building bridge cranes, and intake structure gantry crane are within the scope of license renewal. The others are not within the scope of license renewal, because the turbine building bridge cranes and heater bay gantry crane perform no license renewal intended functions.

In its response, the applicant further indicated that the cranes and monorails that involved a TLAA include Units 1 and 2 refueling platforms, Units 1 and 2 reactor building bridge cranes, intake structure gantry crane, diesel generator bridge cranes, and miscellaneous monorails/hoists. The Units 1 and 2 refueling platforms, Units 1 and 2 reactor building bridge cranes, and the intake structure gantry crane are managed by the Inspection of Overhead Heavy Load and Light Load Handling Systems Program; the diesel generator bridge cranes and miscellaneous monorails/hoists are managed as structural steel under the Structures Monitoring Program.

The staff reviewed the applicant's response and found that the information provided by the applicant is comprehensive and sufficient to answer the three questions posed by the staff. Therefore, the staff's concerns described in RAI 2.4-11 are resolved.

In RAI 2.4-12, dated April 25, 2005, the staff requested that the applicant provide additional information regarding the following Class I Group 6 structures:

(tttttttt) With respect to the intake pumping station, identify items such as hatches and plugs, structural steel embedments, carbon steel boltings, reinforced concrete foundation footings, grouted concrete, and water proofing membrane materials that require an AMR.

(uuuuuuuuu) Regarding the condensate water storage tank foundations and trenches, confirm that the equipment supports and foundations as well as the trenches consist of reinforced concrete components. As appropriate, identify items such as structural steel embedments, carbon steel boltings, grouted concrete, and water proofing membrane materials that require an AMR.

In its response, by letter dated May 11, 2005, the applicant provided the following information:

(a) Hatches and plugs associated with the service water intake structure are considered subcomponents of the "Concrete Above Grade" commodity group. Structural steel embedments are addressed within the "Anchorage/Embedment- Embedded" commodity group. Carbon steel bolting is addressed as a subcomponent of the respective commodity group; such as, "Electrical Support," "Equipment Support," "HVAC Support," etc. Reinforced concrete foundation footings are addressed within the "Concrete Below Grade" commodity group. Grouted concrete is addressed within the "Concrete Above Grade" commodity group. Water proofing membranes are addressed within the "Roof-Membrane/Built-Up" commodity group. These commodities are with the scope of license renewal and require an AMR.

(b) The condensate storage tank (CST) foundation was correlated to a GALL Group 8 structure, not Group 6, and is within the scope of license renewal as addressed in LRA Section 2.4.2.15, "Miscellaneous Structures and Out-Buildings." The commodity groups associated with the CST are: "Anchorage/Embedment –Embedded," "Anchorage/Embedment- Exposed," "Tank Foundation," "Electrical Enclosure," and "Instrument Support." There is no water proofing membrane associated with CST foundation.

The staff verified the information discussed above with the related LRA sections and tables, and found that these components are within the scope of license renewal. On this basis, the staff considers the applicant’s response acceptable; therefore, RAI 2.4-12 is resolved.

In RAI 2.4-13, dated April 25, 2005, the staff stated that based on information provided in LRA Section 2.4, the staff could not identify the insulation and insulation jacketing included in the license renewal scope nor the specific subsets of the insulation and insulation jacketing that are included in LRA Section 2.4 tables. Also, it was unclear to the staff whether the insulation and jacketing on the reactor coolant system has been included within scope. In order to allow the staff to complete the review for the insulation and insulation jacketing, the staff requested that the applicant provide the following information:

(a) Specifically identify the structures and structural components designated within the scope of license renewal that have insulation and/or insulation jacketing, and identify their location in the plant.

(b) List all insulation and insulation jacketing materials associated with item (a), above, that require an AMR and the results of the AMR. Also, identify the AMPs credited to manage aging.

(c) List insulation and insulation jacketing materials associated with item (a) above that do not require aging management, and include a justification for their exclusion in relation to plant-specific operating experience.

In its response, by letter dated May 11, 2005, the applicant stated that the only insulation credited within LRA Section 2.4 is associated with the drywell hot penetrations (LRA Table 2.4.1-1). Insulation and jacketing of the reactor coolant system was not credited in LRA Section 2.4, since drywell internal temperatures are controlled by TSs. The drywell bulk average temperature is managed under TS 3.6.1.4, which requires the plant to enter limiting condition for operation actions if the drywell bulk average temperature exceeds 150 EF.

The applicant also stated that the insulation on hot penetrations is within the scope of license renewal and identified for an AMR in LRA Table 3.5.2-1. No aging effects were identified, based on operating experience; no AMP was specified. Hot penetration temperatures, recorded on chart paper, were reviewed back to 1997. No penetration temperatures exceeded 200 EF, with the highest recorded temperature,185 EF, being on one of the main steam lines. As such, the insulation has proven effective in maintaining hot penetration temperatures below 200 EF.

Based on the applicant’s response, the staff found that the applicant has provided sufficient information in response to the staff’s request and considers RAI 2.4-13 resolved.

In RAI 2.4-14, dated April 25, 2005, the staff stated that for some in-scope building structures, the applicant identified the "Fire Barrier Assembly" as one of the commodity groups requiring an AMR. Therefore, the staff requested that the applicant provide a list of buildings within the scope of license renewal with fire proofing material applied to some of their structural steel members or components as part of fire barriers. The applicant was also requested to discuss how and where these fire proofing materials are included in the AMR as part of the fire barrier review.

In its response, by letter dated May 11, 2005, the applicant stated that the BSEP in-scope buildings with fire proofing material applied to some of their structural steel members or components are the service water intake structure, reactor buildings, diesel generator building, and control building. In LRA Tables 2.4.2-6, 2.4.2-7, 2.4.2-9, and 2.4.2-10, the applicant indicated that the fire proofing material is addressed within the "Sprayed on Coatings" commodity group and is managed by the Fire Protection Program. The staff verified the applicant's response with the LRA sections and tables as well as related UFSAR sections, and found that the applicant had properly addressed this issue. On this basis, the staff's concern described in RAI-2.4-14 is resolved.

Conclusion. The staff reviewed the LRA, related structural components, and RAI responses to determine whether any SSCs that should be within the scope of license renewal had not been identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR had not been identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant had adequately identified the components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and the components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.1 Intake and Discharge Canals

2.4.2.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.1, the applicant described the intake and discharge canals. The intake and discharge canals are part of the circulating water system in which water is taken from the Cape Fear River and discharged into the Atlantic Ocean. The inlet canal begins at the Cape Fear Estuary and terminates at the plant intake structures. Adjacent to the service water intake structure and the circulating water intake structure, within the intake and discharge canals system, are circular sheet-pile caissons acting as a transition between the earthen intake canal and the concrete intake structures. The discharge canal, originating at the southwest area of the plant site, at the discharge weir, travels southwest, crossing under the intracoastal waterway through reinforced concrete pipes. The concrete pipes discharge into a stilling basin, which terminates at the Caswell Beach Pumping Facility.

The failure of NSR SSCs in the intake and discharge canals could potentially prevent the satisfactory accomplishment of an SR function.

The intended functions within the scope of license renewal include the following:

- provides source of cooling water for plant shutdown
- provides structural and/or functional support to NSR equipment

In LRA Table 2.4.2-1, the applicant identified the following intake and discharge canals component types that are within the scope of license renewal and subject to an AMR: canal (intake canal only) and sheet piles.

2.4.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.1 and UFSAR Section 10.4.5.2 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.4.1.1 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.4-6, dated April 25, 2005, the staff stated that as described in UFSAR Section 10.4.5.2, an expanded metal fence and eight traveling screens (four for each unit) are installed in the intake canal to prevent marine life and debris from entering the system. From its review of LRA Section 2.4.2.1, the staff also found that these items are not subject to aging management. Therefore, the staff requested that the applicant submit a more detailed description of these items, including their functions, and describe the technical bases for their exclusion from the scope of license renewal.

In its response, by letter dated May 11, 2005, the applicant indicated that the expanded metal fence is associated with the fish diversion structure. A fish diversion screen is located across the intake canal to keep fish from entering the intake canal, thus minimizing impingement and improving traveling screen reliability. There are no credible DBEs associated with the structure that would prevent or mitigate the completion of an SR function. As such, the fish diversion structure, along with the expanded metal fence, supports no license renewal function and are not considered within the scope of license renewal.

With regard to the eight traveling screens identified in UFSAR Section 10.4.5.2, the applicant stated that these traveling screens are associated with the circulating water system and are located in the circulating water intake structure. Since the intake bays of the circulating water system are classified in the equipment database as NSR structures, and the circulating water intake structure does not contain any components within the scope of license renewal nor support a license renewal intended function, the traveling screens are not within the scope of license renewal.

Based on the applicant's response, the staff concurs with the applicant's assessment that the fish diversion structure, along with the expanded metal fence, and the traveling screens support no license renewal function and thus, considers RAI 2.4-6 resolved.

2.4.2.1.3 Conclusion

The staff reviewed the LRA, related structural/component information, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the intake and discharge canals components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the intake and discharge canals components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.2 Refueling System

2.4.2.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.2, the applicant described the refueling system. The refueling system comprises the refuel platforms, the auxiliary work platform, and various tools, equipment, and structures associated with fuel handling for both new and spent fuel. The refuel platform is unique to each unit; however, the auxiliary work platform and various tools are shared between units. The refuel platform for each unit runs on rails over the fuel pool and reactor well at the 117-foot elevation of the reactor building. The passive physical crane structures, such as the main structural members, bridge, trolley, structural girders, rail system, and anchorage brackets, are considered subcomponents of the refuel platform. The auxiliary work platform is common to both units and is disassembled and moved to support the unit being refueled. Fuel preparation machines are suspended from the side of the spent fuel pools and are used to load new fuel into the fuel pool and to serve as a workstation from which irradiated fuel is de-channeled for inspection.

The failure of NSR SSCs in the refueling system could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide structural and/or functional support to NSR equipment.

In LRA Table 2.4.2-2, the applicant identified the following refueling system component types that are within the scope of license renewal and subject to an AMR: fuel preparation machines, auxiliary work platform, and refueling platforms.

2.4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.2 and Table 2.4.2-2 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-11 (screening of crane/rail systems) discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.2.3 Conclusion

The staff reviewed the LRA, related structural/component information, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concludes that there is reasonable assurance that the applicant adequately identified the refueling system components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the refueling system components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.3 Switchyard and Transformer Yard Structures

2.4.2.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.3, the applicant described the switchyard and transformer yard structures. The relay building and structures in the switchyard and transformer yard have been combined under the one structural system: switchyard and transformer yard structures. These structures are located west of the turbine building. The relay building is shared between units, and each unit has its own switchyard and transformer yard. The design function of these structures is to support, house, and protect components associated with the switchyard, transformer yard, and relay building.

The switchyard and transformer yard structures perform functions that support SBO.

The intended function, within the scope of license renewal, is to provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO.

In LRA Table 2.4.2-3, the applicant identified the following switchyard and transformer yard structures component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- cable tray and conduit

- concrete above grade
- concrete below grade
- electrical enclosure
- electrical support
- equipment support
- piles
- siding
- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.3 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.4.2.3.3 Conclusion

The staff reviewed the LRA and related structural/component information to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concludes that there is reasonable assurance that the applicant adequately identified the switchyard and transformer yard structures components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the switchyard and transformer yard structures components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.4 Monorail Hoists

2.4.2.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.4, the applicant described the monorail hoists. The monorail hoists are structural/mechanical systems used during plant maintenance to move or remove equipment. The monorail hoist system is not shared between units and is not required for abnormal or accident plant operating modes.

The failure of NSR SSCs in the monorail hoists could potentially prevent the satisfactory accomplishment of an SR function.

Monorails are considered to be structural steel within the license renewal civil screening process. The basis for this is that monorails are fixed, permanent, structural members upon which removable hoists are installed when maintenance is required. The hoisting apparatus is typically removed from the monorail when not required for maintenance; however, in some cases the hoists are moved to a safe location on the monorail and secured to prevent inadvertent movement or interaction with SR components. Therefore, only the structural members and anchorages associated with monorail hoists are considered to be license renewal commodities, and the AMR results for monorail hoists are documented under the review of the structural steel commodity in the structures containing the hoists.

2.4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.4 using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff did not identify any omissions. The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-11 (screening of crane/rail systems) discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.4.3 Conclusion

The staff reviewed the LRA,, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the monorail hoists components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the monorail hoists components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.5 Bridge Cranes

2.4.2.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.5, the applicant described the bridge cranes. The bridge cranes are structural/mechanical systems used during plant maintenance to move or remove equipment. The bridge cranes within scope of license renewal are the 125-ton reactor building bridge cranes; the diesel generator bridge cranes; and the refueling jib cranes. Two of the refueling jib cranes have been removed from service. The remaining refueling jib crane and the diesel generator bridge cranes have been screened as structural steel with monorail hoists in the previous subsection. The passive physical crane structures, such as the main structural members, bridge, trolley, structural girders, rail system, and anchorage brackets, are considered subcomponents of the reactor building bridge cranes. The reactor building bridge cranes were designed to Crane Manufacturers Association of America (CMAA) Specification No. 70 (CMAA-70), with a service class of A1, corresponding to a cyclic loading of between 20,000 and 100,000 cycles.

The bridge cranes contain SR components that are relied upon to remain functional during and following DBEs. The intended function, within the scope of license renewal, is to provide structural and/or functional support to SR equipment.

In LRA Table 2.4.2-4, the applicant identified the following bridge cranes component types that are within the scope of license renewal and subject to an AMR: Unit 1 reactor building bridge crane and Unit 2 reactor building bridge crane.

2.4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.5 and the referenced UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-11 (screening of crane/rail systems) discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.5.3 Conclusion

The staff reviewed the LRA, related structural/component information, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the bridge cranes components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the bridge cranes components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.6 Gantry Cranes

2.4.2.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.6, the applicant described the gantry cranes. The gantry cranes are structural/mechanical components used during plant maintenance to move or remove equipment. Gantry cranes are not required for abnormal or accident plant operating modes. The gantry cranes are shared between units and consist of the heater bay gantry crane and the intake structure gantry crane. The gantry cranes are designed in accordance with CMAA-70 and American National Standards Institute (ANSI) B30.2.0-67. Only the intake structure gantry crane is within scope for license renewal, because it has the potential to impact the Class 1 service water intake structure should a structural failure occur. The passive physical crane structures, such as the main structural members, bridge, trolley, structural girders, rail system, and anchorage brackets, are considered subcomponents of the intake structure gantry crane.

The failure of NSR SSCs in the gantry cranes could potentially prevent the satisfactory accomplishment of an SR function.

The intended function, within the scope of license renewal, is to provide structural and/or functional support to NSR equipment. In LRA Table 2.4.2-5, the applicant identified the intake structure gantry crane as the gantry cranes component type that is within the scope of license renewal and subject to an AMR.

2.4.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.6 and the referenced UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-11 (screening of crane/rail systems) discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.6.3 Conclusion

The staff reviewed the LRA, related structural/component information, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the gantry cranes components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the gantry cranes components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.7 Service Water Intake Structure

2.4.2.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.7, the applicant described the service water (SW) intake structure. The SW intake structure is located west of the intake canal and east of the augmented off-gas building. The SW intake structure is a seismic Class 1 structure approximately 104 feet long by 72 feet wide that directs cooling water to the service water pumps via four intake bays from the intake canal. In the SW intake structure, a separate chamber is provided for the 10 SW pumps, and two chambers are provided for the four screen wash water pumps with two pumps per chamber. The purpose of the SW intake structure is to house and protect SW system components. The structure is common to both units. The scope of the SW intake structure initially included the circulating water intake structure concrete and other concrete wetted structures in close proximity to the SW intake structure. However, the seismic Class 2 circulating water intake structure was screened out, because it is located a sufficient distance from the SW intake structure to preclude adverse interactions. The intake structure gantry crane is located within the physical boundary of the SW intake structure; and the crane, crane rails, and associated hardware have been screened with other gantry cranes, above. The concrete structure supporting the crane rails in the vicinity of the SW intake structure is addressed with the SW intake structure.

The SW intake structure contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the SW intake structure could potentially prevent the satisfactory accomplishment of an SR function. In addition, the SW intake structure performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides rated fire barrier
- provides source of cooling water for plant shutdown
- provides missile barrier
- provides structural and/or functional support to NSR equipment

- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provides spray shield or curbs for directing flow

In LRA Table 2.4.2-6, the applicant identified the following SW intake structure component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- cable tray and conduit
- concrete above grade
- concrete below grade
- concrete submerged
- doors and framing/hardware
- electrical enclosure
- electrical support
- equipment support
- fire hose station
- floor drains
- HVAC support
- instrument racks
- instrument suppport
- masonry walls
- penetration
- pipe support
- roof-membrane / built-up
- seals and gaskets
- spray shield
- sprayed on coatings
- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.7 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAIs 2.4-8, 2.4-10, 2.4-12, and 2.4-14 discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.7.3 Conclusion

The staff reviewed the LRA, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the SW intake structure components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the SW intake structure components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.8 Reactor Building

2.4.2.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.8, the applicant described the reactor building. The reactor building encloses the primary containment which consists of the drywell and pressure suppression chamber. The reactor building houses the refueling and reactor service equipment, new and spent fuel storage facilities, and other reactor services and auxiliary equipment. The reactor building serves as a secondary containment during normal plant operation when the primary containment is functional. In addition, the reactor building serves as the containment boundary during reactor refueling and maintenance operations, when the primary containment is open. Each unit has a reactor building; it is not a common or shared structure. The secondary containment system includes the secondary containment (reactor building) structure and the SR systems provided to control the ventilation and cleanup of potentially contaminated volumes, exclusive of the primary containment, following a design-basis accident. The safety objective of the secondary containment is to limit the release of radioactivity to the environs after an accident so that the resulting exposures are kept to a practical minimum and are within regulatory limits. The secondary containment minimizes the consequences of an accident by providing a controlled release of the reactor building atmosphere through filters at an elevated point.

The reactor building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the reactor building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the reactor building performs functions that support EQ, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides pressure boundary and/or fission product barrier
- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides rated fire barrier
- provides missile barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provides pipe whip restraint and/or jet impingement protection
- provides spray shield or curbs for directing flow

In LRA Table 2.4.2-7, the applicant identified the following reactor building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- bellows (RCIC line bellows - MSIV pit)
- blow-out panel
- cable tray and conduit
- concrete above grade
- concrete below grade
- concrete curbs
- damper mounting
- doors and framing/hardware (includes airlock doors)
- electrical enclosure
- electrical support

- equipment support
- fire barrier assembly
- fire hose station
- floor drains
- HVAC support
- instrument racks
- instrument support
- liner (reactor cavity and spent fuel pool)
- masonry walls
- penetration (mechanical and electrical)
- pipe support
- roof-membrane / built-up
- seals and gaskets
- siding (pressure boundary)
- slide bearing plate (torus radial beams and spent fuel rack support)
- spent fuel storage rack
- spray shield
- sprayed on coatings
- structural steel: platforms, stairways, mezzanines, and hardware
- tendons (concrete girders spanning the reactor building)
- whip restraints

2.4.2.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.8 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review of LRA Section 2.4.2.8 identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.4-3, dated April 25, 2005, the staff stated that Group 2 structures defined in GALL Report, Chapter III, include the BWR reactor building with steel superstructure (enclosure building) and should be included within the scope of license renewal. As shown in LRA Table 2.4.2-7, it was not clear to the staff whether the entire enclosure building (including the metal structure, metal panels) was within the scope of license renewal. Therefore, the staff requested that the applicant clarify the extent to which the enclosure building is within the scope of license renewal, and to identify the location(s) of all its components in the LRA.

In its response dated May 11, 2005, the applicant indicated that the entire reactor building, including the metal superstructure, is within the scope of license renewal. The structural steel associated with the superstructure is addressed within the "Structural Steel" commodity group, the metal panels are addressed within the "Siding" and "Blow-Out Panel" commodity groups, and the roof is addressed within the "Roof-Membrane/Built-Up" commodity group, in LRA Table 2.4.2-7. With confirmation that the metal superstructure and metal panels are within the scope of license renewal, the staff's concern described in RAI 2.4-3 is resolved.

In RAI 2.4-5, dated April 25, 2005, the staff stated that in LRA Section 2.4.1.1, the applicant provided a discussion of the scoping and screening results for the primary containment structure. It was the staff's understanding that this LRA section addresses not only the primary containment (drywell, pressure suppression chamber, and vent system connecting the two structures), but all the structures inside the primary containment, all attachments to the containment, and the containment supports. LRA Table 2.4.1-1 identifies the primary containment component types requiring an AMR and the associated component intended function(s). Since LRA Table 2.4.1-1 combines many components under a single component type, the staff requested that the applicant identify the component type intended to cover the specific components listed below as (a) through (f); or to identify the locations in the LRA where these specific components are addressed. If these specific components are not considered to be within the scope of license renewal, the staff requested that the applicant provide the technical bases for their exclusion:

(a) stabilizers between the reactor vessel and biological shield wall

(b) stabilizer between the biological shield wall and drywell wall

(c) biological shield wall anchor bolts

(d) reactor vessel anchor bolts

(e) reactor vessel support ring girder including anchor bolts and reactor vessel support pedestal

(f) drywell head closure bolts and double gasket, tongue-and-groove seal arrangement

In its response, by letter dated May 11, 2005, the applicant responded to the staff's question as follows:

(a) RPV stabilizers, located between the RPV and the biological shield wall, are within the scope of license renewal and are addressed within the "RPV Support" commodity group.

(b) Stabilizers between the biological shield wall and drywell wall are seismic ties. These stabilizers are within the scope of license renewal and are addressed within the "Structural Steel" commodity group.

(c) Biological shield wall anchor bolts associated with the biological shield wall are considered subcomponents of the "Sacrificial Shield Wall" commodity group, which is within the scope of license renewal.

(d) Reactor vessel anchor bolts associated with the reactor vessel support are considered subcomponents of the "RPV Support" commodity group, which is within the scope of license renewal.

(e) Reactor vessel support ring girder and anchor bolts are subcomponents of the "RPV Support" commodity group. The reactor vessel support pedestal is addressed within the "Concrete Above Grade" commodity group, which is within the scope of license renewal.

(f) The drywell head closure bolts and double gasket, tongue-and-groove seal arrangement are subcomponents of the "Drywell Head" commodity group, which is within the scope for license renewal. The associated seals are for the drywell head are addressed within the "Seals and Gaskets" commodity group, which is also within the scope of license renewal.

The staff found the applicant’s response reasonable and acceptable. Therefore, the concerns described in RAI 2.4-5 are resolved.

In RAI 2.4-5, dated April 25, 2005, the staff stated that in its review of LRA Table 2.4.2-7, the staff found that a number of components are not listed. Therefore, the staff specifically requested that the applicant provide a description of the neutron-absorbing sheets used for the spent fuel storage racks, and confirm that they are part of the spent fuel storage racks that are within the scope of license renewal.

In its response, by letter dated May 11, 2005, the applicant stated that boral plates are an integral non-structural part of the basic fuel storage tube. These plates are sandwiched between the inner and outer wall of the storage tube and are not subject to dislocation, deterioration, or removal. Boral is considered a subcomponent of the "Spent Fuel Storage Rack" commodity group. As indicated in LRA Table 3.5.2-8, the boral sandwiched between two stainless steel tubes is within the scope of license renewal. Based on the above response, the staffs concern described in RAI 2.4-7 is resolved.

In RAI 2.4-9. dated April 25, 2005, the staff stated that, as a result of its review of LRA Section 2.4.2.8 and Table 2.4.2-7, the staff requested that the applicant clarify whether the reactor building pipe penetrations include some type of silicone rubber seals that allow for pipe movement while providing a seal between the pipe and the reactor buildings to maintain the differential pressure. In addition, the applicant was requested to confirm whether these penetration seals are designated within the scope of license renewal and are included in LRA Table 2.4.2.7.

In the response, by letter dated May 11, 2005, the applicant indicated that the reactor building pipe penetrations are sealed around the piping by installation of an expandable rubber seal or other suitable fill material. These penetrations are within the scope of the AMR and are included in LRA Table 2.4.2-7. On this basis, the staff’s concern described in RAI 2.4-9 is resolved.

2.4.2.8.3 Conclusion

The staff reviewed the LRA, and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the reactor building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the reactor building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.9 Augmented Off-Gas Building

2.4.2.9.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.9, the applicant described the AOG building. The AOG building, also known as the nitrogen and off-gas services building, is located east of the Unit 1 reactor building and west of the SW intake structure. The AOG building is constructed of reinforced concrete with three working elevations. The primary purpose of the AOG building is to house SR SSCs that provide a makeup source of nitrogen to control combustible gases in the reactor containment following a LOCA. The primary system providing the combustible gas control is the CAD subsystem of the CAC system, which is an ESF. Portions of the CAD are located in the AOG building. The AOG building is a seismic Class 1 structure designed to meet seismic, tornado, hurricane, and flooding requirements.

The AOG building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the AOG building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the AOG building performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides rated fire barrier
- provides missile barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO

In LRA Table 2.4.2-8, the applicant identified the following AOG building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- cable tray and conduit
- concrete above grade
- concrete below grade
- doors and framing/hardware
- electrical enclosure
- electircal support
- equipment support
- fire hose station
- instrument racks
- instrument support
- masonry walls
- penetrations (mechanical and electrical)
- pipe support
- slide bearing plate (nitrogen tank supports)
- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.8 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAIs 2.4-8 and 2.4-10, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.9.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the AOG building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the AOG building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.10 Diesel Generator Building

2.4.2.10.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.10, the applicant described the DG building. The DG building is located east of the radwaste building and the reactor buildings. The diesel generator building is a reinforced concrete structure consisting of three levels housing an electrical spreading area, four diesel generator units, auxiliary equipment, electrical switchgear, diesel generator intake and exhaust equipment, and building ventilating equipment. The DG exhaust silencers are located on the DG building roof. After passing through the silencers, exhaust gases are routed away from DG building structures and do not impinge on any structures that could fall and block the DG exhaust flow path. Underground diesel fuel storage tanks are located to the east of the building in a reinforced concrete vault (i.e., the tank building).

The DG building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the DG building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the DG building performs functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides rated fire barrier
- provides missile barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provides spray shield or curbs for directing flow

In LRA Table 2.4.2-9, the applicant identified the following DG building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded

- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electircal supports, equipment supports, HVAC supports, instrument supports, etc.)
- blow-out panel
- cable tray and conduit
- concrete above grade
- concrete below grade
- concrete curbs
- damper mounting
- doors and framing/hardware
- electrical enclosure
- electrical support
- equipment support
- fire barrier assembly
- fire hose station
- floor drains
- HVAC support
- instrument racks
- instrument support
- masonry walls
- penetrations (mechanical and electrical)
- pipe support
- roof-membrane/built-up
- siding
- spray shield
- sprayed on coatings
- structural steel: platforms, stairways, mezzanines, and hardware
- vibration isolators (at the AMR stage, this commodity was consolidated within the proper support group: piping supports or HVAC supports)

2.4.2.10.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1.10 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAIs 2.4-8, 2.4-10, and 2.4-14, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.10.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the DG building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the DG building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.11 Control Building

2.4.2.11.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.11, the applicant described the control building. The control building is a reinforced concrete structure located inside the protected area, between the two reactor buildings. The control building is a shared structure between the two units and is subdivided into the following principal areas: (1) cable spreading areas and battery rooms, (2) control room and electronic equipment rooms, and (3) HVAC equipment room located in a one-story penthouse. The control building is a seismic Class 1 structure designed to support, house, and protect SR systems and components. In addition, the control building supports the post-accident habitability function by providing radiation shielding and a barrier to fission products for control room operating staff.

The control building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the control building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the control building performs functions that support fire protection, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides pressure boundary and/or fission product barrier
- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides rated fire barrier

- provides missile barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO

In LRA Table 2.4.2-10, the applicant identified the following control building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- battery rack
- cable tray and conduit
- concrete above grade
- concrete below grade
- control room ceiling
- damper mounting
- doors and framing/hardware
- electrical enclosure
- electrical support
- equipment support
- fire barrier assembly
- fire hose station
- HVAC support
- instrument racks
- instrument support
- masonry walls
- penetration (mechanical and electrical)
- pipe support
- raised floor
- roof-membrane/built-up
- seals and gaskets
- sprayed on coatings

- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.11.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.11 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAIs 2.4-8, 2.4-10, and 2.4-14, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.11.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the control building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the control building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.12 Turbine Building

2.4.2.12.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.12, the applicant described the turbine building. The turbine building is located north of the service building and west of reactor and control buildings, within the protected area. The turbine building and adjacent auxiliary bay houses the turbine generators, condensers, reactor feedwater systems, as well as other turbine plant auxiliary equipment, electrical switchgear and reactor recirculation pump motor generator sets. The building is supported on spread footings founded on structural backfill and is constructed of reinforced concrete up to and including the operating floor. Reinforced concrete shield walls for equipment are provided above the operating floor for radiation protection. The superstructure above the operating floor is a steel-framed crane bay with panel siding and roof constructed of metal deck, insulation, and membrane roofing. The turbine building is a seismic Class 2 structure that provides support for equipment credited in the performance of the AST function.

The turbine building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the turbine building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the turbine building performs functions that support fire protection, ATWS, and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides rated fire barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO

In LRA Table 2.4.2-11, the applicant identified the following turbine building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- cable tray and conduit
- concrete above grade
- concrete below grade
- concrete curbs
- doors and framing/hardware
- electrical enclosure
- electrical support
- equipment support
- fire barrier assembly
- fire hose station
- instrument racks
- instrument support
- masonry walls
- penetrations (mechanical and electrical)
- pipe support
- roof-membrane/built-up

- siding
- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.12 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAIs 2.4-8 and 2.4-10, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.12.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the turbine building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the turbine building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.13 Radwaste Building

2.4.2.13.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.13, the applicant described the radwaste building. The radwaste building is located inside the protected area and is constructed on a reinforced concrete mat founded on structural fill. The building consists of two principal levels constructed with reinforced concrete walls and slabs. The thickness of the walls and slabs was determined by shielding and structural requirements. The radwaste building was designed as a Class 2 structure; however, to ensure the integrity of the Class 1 control building and Class 1 storage tanks in the radwaste building basement, the radwaste building was designed for Class 1 seismic loads. The radwaste building foundation mat supports the following augmented quality equipment: (1) concentrated waste tank, (2) waste collector tank, and (3) waste neutralizer tanks. The radwaste building is a shared structure between the two units. The design function of the radwaste building is to support, house, and protect radwaste systems and components.

The radwaste building contains SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the radwaste building could potentially prevent the satisfactory accomplishment of an SR function. In addition, the radwaste building performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides missile barrier
- provides structural and/or functional support to NSR equipment
- provides a protective barrier for internal/external flood event
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO

In LRA Table 2.4.2-12, the applicant identified the following radwaste building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- cable tray and conduit
- concrete above grade
- concrete below grade
- doors and framing/hardware
- electrical enclosure
- electrical support
- fire hose station
- instrument support
- pipe support
- roof-membrane/built-up

2.4.2.13.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.13 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-10, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.13.3 Conclusion

The staff reviewed the LRA and RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the radwaste building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the radwaste building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.14 Water Treatment Building

2.4.2.14.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.14, the applicant described the water treatment building. The water treatment building is a steel frame structure located within the protected area north of the Unit 1 reactor building. The water treatment building contains fire protection pumps and other fire protection-related SSCs, which support BSEP fire protection commitments. The water treatment building is a single structure that contains both Units 1 and 2 components. It is a seismic Class 2 structure that does not support any SR components or functions.

The water treatment building performs functions that support fire protection.

The intended functions within the scope of license renewal include the following:

- provides rated fire barrier
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO

In LRA Table 2.4.2-13, the applicant identified the following water treatment building component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed (at the AMR stage, this commodity was consolidated within the proper support group: piping supports, electrical supports, equipment supports, HVAC supports, instrument supports, etc.)
- battery rack

- cable tray and conduit
- concrete above grade
- concrete below grade
- electrical enclosure
- electrical support
- equipment support
- fire barrier assembly
- instrument support
- pipe support
- siding
- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.14.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1.14 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-12, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.14.3 Conclusion

The staff reviewed the LRA, related structural/component information, and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the water treatment building components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the water treatment building components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.15 Miscellaneous Structures and Out-Buildings

2.4.2.15.1 Summary of Technical Information in the Application

In LRA Section 2.4.2.15, the applicant described the miscellaneous structures and out-buildings. The miscellaneous structures and out-buildings consist of those structures and outbuildings that are stand-alone structures and not part of, or attached to, one of the major building systems. The miscellaneous structures and out-buildings evaluated for license renewal include foundations and structural support arrangements for mechanical system equipment such as outside tanks, electrical racks, and oil loading stations. Typically, the license renewal classification for miscellaneous structures or out-buildings is the same as the classification of the electrical or mechanical SCs that the miscellaneous structures or out-buildings support. The following miscellaneous structures and out-buildings were determined to be within the scope of license renewal: (1) HPCI CO_2 bottle storage buildings, Units 1 and 2, (2) condensate storage tank foundations, Units 1 and 2, (3) diesel generator building oil tank room foam system concentrate tank, (4) SW valve pits, Units 1 and 2, (5) fuel oil storage tank foundation, (6) fire protection water tank foundation, (7) stack and filter house, (8) manholes and duct banks, and (9) demineralized water tank.

The miscellaneous structures and out-buildings contain SR components that are relied upon to remain functional during and following DBEs. The failure of NSR SSCs in the miscellaneous structures and out-buildings could potentially prevent the satisfactory accomplishment of an SR function. In addition, the miscellaneous structures and out-buildings perform functions that support fire protection and SBO.

The intended functions within the scope of license renewal include the following:

- provides structural and/or functional support to SR equipment
- provides shelter/protection to SR equipment
- provides structural and/or functional support to NSR equipment
- provides a path for release of filtered or unfiltered gaseous discharge
- provides structural support and/or shelter to components required for fire protection, ATWS, and/or SBO

In LRA Table 2.4.2-14, the applicant identified the following miscellaneous structures and out-buildings component types that are within the scope of license renewal and subject to an AMR:

- anchorage/embedment - embedded
- anchorage/embedments - exposed
- cable tray and conduit
- concrete above grade
- concrete below grade
- concrete BWR vent stack
- tank foundation
- electrical enclosure
- electrical support
- instrument support
- manholes (addressed under concrete below grade)
- piles
- siding

- structural steel: platforms, stairways, mezzanines, and hardware

2.4.2.15.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.15 and the UFSAR using the evaluation methodology described in SER Section 2.4. The staff conducted its review in accordance with the guidance described in SRP-LR Section 2.4.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant had not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant had identified as being within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In addition to RAI 2.4-10, discussed in Section 2.4.2 above, no other RAI was identified.

2.4.2.15.3 Conclusion

The staff reviewed the LRA and RAI response to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the miscellaneous structures and out-buildings components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant adequately identified the miscellaneous structures and out-buildings components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results – Electrical & Instrumentation and Controls Systems

This section documents the staff's review of the applicant's scoping and screening results for electrical and I&C systems. Specifically, this section discusses the electrical and instrumentation and controls component commodity groups system.

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived mechanical SSCs that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This approach allowed the staff to confirm that there were no omissions of electrical and I&C system components that meet the scoping criteria and are subject to an AMR.

Staff Evaluation Methodology: The staff's evaluation of the information provided in the LRA was performed in the same manner for all electrical and I&C systems. The objective of the review was to determine if the components and supporting structures for a specific electrical and I&C system, that appeared to meet the scoping criteria specified in the Rule, were identified by the applicant as within the scope of license renewal, in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to verify that all long-lived, passive components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Scoping: To perform its evaluation, the staff reviewed the applicable LRA section and associated component drawings, focusing its review on components that had not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the updated final safety analysis report (UFSAR), for each electrical and I&C system component to determine if the applicant had omitted components with intended functions delineated under 10 CFR 54.4(a) from the scope of license renewal. The staff also reviewed the licensing basis documents to determine if all intended functions delineated under 10 CFR 54.4(a) were specified in the LRA. If omissions were identified, the staff requested additional information to resolve the discrepancies.

Screening: Once the staff completed its review of the scoping results, the staff evaluated the applicant's screening results. For those systems and components with intended functions, the staff sought to determine if the functions are performed with moving parts or a change in configuration or properties, or if they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those that did not meet either of these criteria, the staff sought to confirm that these electrical and I&C systems and components were subject to an AMR as required by 10 CFR 54.21(a)(1). If discrepancies were identified, the staff requested additional information to resolve them.

After applying the scoping and screening methodology, the applicant categorized the components requiring an AMR into passive commodity groups. In LRA Section 2.5.1, the applicant identified the SCs of the electrical and I&C systems that are subject to an AMR for license renewal.

2.5.1 Electrical and Instrumentation and Controls Component Commodity Groups

The applicant performed the screening for electrical/I&C components on a generic component commodity group basis for the electrical/I&C systems within the scope of license renewal. The in-scope electrical/I&C component commodity group systems and structures identified at BSEP in LRA Section 2.5.1 are listed below:

<table>
<tr><th colspan="4">ELECTRICAL/I&C COMPONENT COMMODITY GROUPS FOR IN-SCOPE SYSTEMS AND STRUCTURES AT BSEP</th></tr>
<tr><td>Alarm Units</td><td rowspan="3">Electrical portions of Electrical/I&C Penetration Assemblies</td><td>Light Bulbs</td><td>Solenoid Operators</td></tr>
<tr><td rowspan="2">Analyzers</td><td>Load Centers</td><td>Signal Conditioners</td></tr>
<tr><td>Loop Controllers</td><td>Solid-State Devices</td></tr>
<tr><td>Annunciators</td><td>Elements</td><td>Meters</td><td>Splices</td></tr>
<tr><td>Batteries</td><td>Fuses</td><td>Motor Control Centers</td><td>Surge Arresters</td></tr>
<tr><td>Phase bus</td><td>Generators</td><td>Motors</td><td>Switches</td></tr>
<tr><td>Chargers</td><td>Heat Tracing</td><td>Power Distribution Panels</td><td>Switchgear</td></tr>
<tr><td>Circuit Breakers</td><td>Heaters</td><td>Power Supplies</td><td>Switchyard Bus</td></tr>
<tr><td>Converters</td><td>High-voltage Insulators</td><td>Radiation Monitors</td><td>Terminal Blocks</td></tr>
</table>

ELECTRICAL/I&C COMPONENT COMMODITY GROUPS FOR IN-SCOPE SYSTEMS AND STRUCTURES AT BSEP			
Communication Equipment	Indicators	Recorders	Thermocouples
	Insulated Cables and Connections	Regulators	Transducers
Electrical Controls and Panel Internal Component Assemblies		Relays	Transformers
	Inverters	RTDs	Transmitters
	Isolators	Sensors	Transmission Conductors

The applicant described the supporting structures and components of the electrical/I&C component commodity groups in the following sections of the LRA:

- 2.5.3.1 non-EQ insulated cables and connections
- 2.5.3.2 phase bus
- 2.5.3.3 non-EQ electrical/I&C penetration assemblies
- 2.5.3.4 high voltage insulators
- 2.5.3.5 switchyard bus
- 2.5.3.6 transmission conductors

The corresponding subsections of this SER (2.5.1.1 – 2.5.1.6, respectively) present the staff's review findings with respect to the electrical/I&C component commodity groups for Units 1 and 2. SER Section 2.5.1.7 addresses the SBO, which is presented in LRA Section 2.1.4.2.

In its RAIs 2.5-1 and 2.5.1-1, dated May 18, 2005, the staff requested that the applicant clarify why switchyard bus connections and transmission conductor connections are not included in the electrical/I&C component commodity groups table.

In its response, by letter dated June 14, 2005, the applicant stated that the connections associated with the commodity groups "Switchyard Bus" and "Transmission Conductors" are included in these commodity groups.

The terminology shown in the table was selected for consistency with previous LRAs and to standardize electrical/I&C component commodity group terminology. Connections were evaluated as part of the AMR for the commodity groups. Switchyard bus connections were evaluated as shown in LRA Table 3.6.2-1, plant-specific note 607; while transmission conductor connections were evaluated as shown in LRA Table 3.6.2-1, plant-specific note 608.

Based on the above information, the staff found that the applicant adequately identified the switchyard bus and the transmission conductors connections that are subject to an AMR. Therefore, the staff's concerns described in RAIs 2.5-1 and 2.5.1-1 are resolved.

2.5.1.1 Non-EQ Insulated Cables and Connections

2.5.1.1.1 Summary of Technical Information in the Application

The function of insulated cables and connections is to electrically connect specified sections of an electrical circuit to deliver voltage, current or signals. Electrical cables and their connections are reviewed as a single component commodity group. The types of connections included in this review are splices, connectors, fuse holders, and terminal blocks.

In LRA Section 2.5.3.1, the applicant stated that numerous insulated cables and connections are included in the EQ Program and, therefore, are not subject to an AMR in accordance with the screening criteria of 10 CFR 54.21(a)(1)(ii). Insulated cables and connections that perform an intended function within the scope of license renewal, but are not included in the EQ Program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR. However, insulated cables and connections inside the enclosure of an active device (e.g., motor leads and connections, and cables and connections internal to relays, chargers, switchgear, transformers, power supplies, etc.) are maintained along with the other subcomponents and piece-parts inside the enclosure and are not subject to an AMR.

In LRA Section 2.5.3.1, the applicant identified the non-EQ insulated cables and connections component types that are within the scope of license renewal and subject to an AMR such as splices, connectors, fuse holders, and terminal blocks.

In LRA Section 2.1.4.5, the applicant stated that ISG-5 for screening of fuse holders determined that fuse holders that are not part of an active component or assembly, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards, are considered to be passive electrical components and, therefore, require an AMR. Such fuse holders are evaluated for license renewal in the same manner as terminal blocks and other types of electrical connections. ISG-5 also determined that fuse holders that are piece parts of an active assembly are not subject to an AMR, because they would be subject to periodic inspection and maintenance in accordance with the maintenance and surveillance activities applicable to the active assembly.

The applicant performed a review of fuse holders, using the guidance of ISG-5, and determined that those fuse holders are part of a larger (active) assembly. Therefore, it was concluded that no fuse holders require an AMR.

2.5.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.1 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The applicant performed a review of fuse holders, using the guidance of ISG-5, and determined that those fuse holders are part of a larger (active) assembly. Therefore, the staff concluded that no fuse holders require an AMR.

The staff found that the applicant correctly identified the cables and connections as component commodity group that perform their function without moving parts or a change in configuration or properties (passive and long lived) and are, therefore, subject to an AMR.

2.5.1.1.3 Conclusion

The staff reviewed the LRA and the UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified those cables and connectors that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.2 Phase Bus

2.5.1.2.1 Summary of Technical Information in the Application

In LRA Section 2.5.3.2, the applicant described the phase bus. A phase bus is used to connect two or more elements (electrical equipment such as switchgear and transformers) of an electrical circuit. Isolated phase bus is an electrical bus in which each phase conductor is enclosed by an individual metal housing separated from adjacent conductor housings by an air space. Non-segregated phase bus is an electrical bus constructed with all phase conductors in a common enclosure without barriers (only air space) between the phases.

The phase bus contains SR components that are relied upon to remain functional during and following DBEs.

The intended function, within the scope of license renewal, is to provide electrical continuity.

In LRA Section 2.5.3.2, the applicant identified the following phase bus component types that are within the scope of license renewal and subject to an AMR:

- portions of the isolated phase bus used for backfeeding offsite power to the main transformers and unit auxiliary transformers (UATs) during recovery from an SBO event
- 4.16 kilvolt (kV), non-segregated phase bus connecting site auxiliary transformer (SAT) #1 disconnect links to 4.16 kV buses 1C and 1D
- 4.16 kV, non-segregated phase bus connecting SAT #2 disconnect links to 4.16 kV buses 2C and 2D
- 4.16 kV, non-segregated phase bus connecting UAT #1 to buses 1C and 1D
- 4.16 kV, non-segregated phase bus connecting UAT #2 to buses 2C and 2D
- 4.16 kV, non-segregated phase bus connecting emergency switchgear E1 and E2
- 4.16 kV, non-segregated phase bus connecting emergency switchgear E1 and E3

- 4.16 kV, non-segregated phase bus connecting emergency switchgear E2 and E4
- 4.16 kV, non-segregated phase bus connecting emergency switchgear E3 and E4
- 480V, non-segregated phase bus connecting unit substations E5 and E6
- 480V, non segregated phase bus connecting unit substations E7 and E8

2.5.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.2 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The phase buses identified by the applicant consist of non-segregated phase buses that are used for backfeeding offsite power during recovery from an SBO event, 4.16 kV, and 480 V plant-wide to conduct electrical power (voltage and current), either continuously or intermittently between various equipment and components.

2.5.1.2.3 Conclusion

The staff reviewed the LRA and the UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the phase bus that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.3 Non-EQ Electrical/I&C Penetration Assemblies

2.5.1.3.1 Summary of Technical Information in the Application

In LRA Section 2.5.3.3, the applicant described the non-EQ electrical/I&C penetration assemblies. Many electrical/I&C penetration assemblies are included in the EQ Program and, therefore, do not meet the criterion of 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. A review of the remaining, non-EQ, electrical/I&C penetration assemblies demonstrated that most were not within the scope of license renewal because they either did not contain any electrical circuits (such as, spare penetrations) and therefore did not support an electrical intended function, or they did not contain electrical circuits that supported a system-level electrical/I&C intended function for license renewal. After eliminating these penetration assemblies from further consideration, a small number of non-EQ Program penetrations remained. These were determined to meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are, therefore, subject to an AMR.

The non-EQ electrical/I&C penetration assemblies contain SR components that are relied upon to remain functional during and following DBEs.

The intended function, within the scope of license renewal, is to provide electrical continuity.

2.5.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.4 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The electrical penetrations identified by the applicant requiring an AMR are non-EQ related and used plant-wide to conduct electrical power (voltage and current), either continuously or intermittently between two sections of the electrical I&C circuits supplying power to various equipment in the containment.

2.5.1.3.3 Conclusion

The staff reviewed the LRA and the UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified non-EQ electrical/I&C penetration assemblies that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.4 High Voltage Insulators

2.5.1.4.1 Summary of Technical Information in the Application

In LRA Section 2.5.3.4, the applicant described the high-voltage insulators. The high-voltage insulators are provided on the circuits used to supply power from the switchyard to plant buses during recovery from an SBO. The function of high-voltage insulators is to insulate and support electrical conductors.

The high-voltage insulators contain SR components that are relied upon to remain functional during and following DBEs. In addition, the high-voltage insulators perform functions that support SBO.

The intended function, within the scope of license renewal, is to insulate and support an electrical conductor.

In LRA Section 2.5.3.4, the applicant identified the high-voltage insulators component types that are within the scope of license renewal and subject to an AMR.

2.5.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.4 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

As identified by the applicant, the high-voltage insulators are associated with the in-scope portion of the offsite power system as station post insulators providing support for the switchyard bus connecting the high-voltage station auxiliary transformers and the circuit switchers. In addition, they support the circuit switches themselves.

2.5.1.4.3 Conclusion

The staff reviewed the LRA and the UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the high-voltage insulators that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.5 Switchyard Bus

2.5.1.5.1 Summary of Technical Information in the Application

In LRA Section 2.5.3.5, the applicant described the switchyard bus. The switchyard bus provides a portion of the circuits supplying power from the switchyard to plant buses during recovery from an SBO. The function of the switchyard bus is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

The switchyard bus contains SR components that are relied upon to remain functional during and following DBEs.

The intended function, within the scope of license renewal, is to provide electrical continuity.

In LRA Section 2.5.3.5, the applicant identified the switchyard bus component types that are within the scope of license renewal and subject to an AMR.

2.5.1.5.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.5 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

As identified by the applicant, the switchyard bus associated within the scope of license renewal is the portion of the offsite power system interconnections between the Unit 1 circuit switcher and the high-voltage station auxiliary transformer, and between the Unit 2 circuit switcher and the high-voltage station auxiliary transformer.

2.5.1.5.3 Conclusion

The staff reviewed the LRA and the UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the switchyard bus that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.6 Transmission Conductors

2.5.1.6.1 Summary of Technical Information in the Application

In LRA Section 2.5.3.6, the applicant described the transmission conductors. The transmission conductors provide a portion of the circuits used to supply power from the switchyard to plant buses during recovery from an SBO. The function of transmission conductors is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

The transmission conductors contain SR components that are relied upon to remain functional during and following DBEs. The intended function, within the scope of license renewal, is to provide electrical continuity.

In LRA Section 2.5.3.6, the applicant identified the transmission conductor components that are within the scope of license renewal and subject to an AMR.

2.5.1.6.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.6 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In conducting its review, the staff evaluated the system functions described in the LRA and UFSAR in accordance with the requirements of 10 CFR 54.4(a) to verify that the applicant did not omit from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as being within the scope of license renewal to verify that the applicant did not omit any passive and long-lived components that should be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The transmission conductors identified by the applicant that are within the scope of license renewal are the short connections from each unit's high-voltage station auxiliary transformer surge arresters to sections of aluminum switchyard bus. These conductors are aluminum jumper cables with a steel core (ACSR) in short sections between rigidly supported connecting equipment.

2.5.1.6.3 Conclusion

The staff reviewed the LRA and the UFSAR to determine whether any SSCs that should be within the scope of license renewal were not omitted by the applicant. No omissions were identified. In addition, the staff performed a review to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were identified. On the basis of its review, the staff concluded that there is reasonable assurance that the applicant adequately identified the transmission conductors that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1.7 Station Blackout (SBO)

2.5.1.7.1 Summary of Technical Information in the Application

In LRA Section 2.1.4.2, the applicant stated that staff guidance ISG-2 clarifies that the SSCs relied on for recovery from an SBO, in addition to SSCs relied on for coping with an SBO, should be within the scope of license renewal. The staff position is that the plant system portion of the offsite power system should be included within scope. Including SBO recovery equipment within the scope of license renewal brings into scope various electrical components and associated structures associated with providing offsite power via the switchyard to plant electrical buses.

The following specific systems support recovery from an SBO event and have been included in the scope of license renewal in accordance with ISG-2.

- 230KV switchyard system (includes the main power transformers)
- startup auxiliary transformers and unit auxiliary transformers
- generator iso-phase bus system
- switchyard relay building
- structural components/commodities that support the above systems.

The passive, long-lived electrical components composing the restoration power path for offsite power that are subject to an AMR are as follows:

- generator isolated phase (iso-phase) bus duct
- non-segregated 4.16KV & 480V bus duct
- high-voltage insulators
- switchyard bus
- insulated cables and connections
- transmission conductors and connections

2.5.1.7.2 Staff Evaluation

The staff reviewed LRA Section 2.1.4.2 using the evaluation methodology described in SER Section 2.5. The staff conducted its review in accordance with the guidance described in SRP-LR, Section 2.5.

In RAI 2.1.4.2.1, dated May 18, 2005, the staff requested that the applicant (1) identify whether there are any underground power circuits used in the SBO recovery paths; (2) provide a detailed description of the SBO recovery path; and (3) confirm whether the motor-operated disconnect (MOD) qualified as a first breaker in the SBO recovery path.

In its response, by letter dated June 14, 2005, the applicant stated:

> (206) There are no underground power circuits used in the SBO recovery path.
>
> (207) There are two offsite sources of auxiliary power available when recovering from an SBO event. The first (i.e., preferred) source of offsite power is via the Startup Auxiliary Transformer (SAT). The SAT is fed from the 230KV Switchyard, which has multiple sources of supply from the 230KV transmission and distribution system. The BSEP Unit 1 and Unit 2 230KV Switchyards are electrically independent of each other and have no crosstie capabilities. The second (i.e., alternate) source of offsite power when recovering from an SBO event is obtained by backfeeding through the Main Transformers from the 230KV Switchyard to the Unit Auxiliary Transformer (UAT). Prior to backfeeding the Main

Transformers, the no-load disconnect switch to the Main Generator must be opened. See Figure 2.1-2 of the LRA for a drawing of the SBO recovery path.

(208) Unit 2 Switchyard MOD M15 and MOD M16 have been replaced with 230KV gas-filled power circuit breakers (PCBs). PCB M15 and PCB M16 represent the first breaker used for the preferred source of offsite power in the Unit 2 SBO recovery path.

The License Renewal boundary for the Unit 1 SBO recovery path is currently MOD M11 and MOD M12. These MODs are scheduled to be replaced with circuit breakers during the spring of 2006. Pending installation of the Unit 1 circuit breakers, the License Renewal boundary for the Unit 1 SBO recovery path will be at the circuit breakers for the individual offsite feeders.

For both Unit 1 and Unit 2, the License Renewal boundary for the SBO recovery path will be at the first circuit breaker, consistent with ISG-2.

For a detailed description of the SBO recovery path, see the response to RAI 2.1.4.2-1.b above.

The staff concurred with the applicant’s response. Therefore, the staff’s concern described in RAI 2.1.4-1 is resolved.

2.5.1.7.3 Conclusion

The staff reviewed the LRA and the above RAI response for scoping and screening results of SBO components to determine whether any SCCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. On the basis of this review, the staff concluded that the applicant had adequately identified the components of the SBO system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that that the applicant has adequately identified the components of the SBO system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) contains the staff's evaluation of the applicant's aging management programs (AMPs) and aging management reviews (AMRs). In its LRA Appendix B, the applicant described the 34 AMPs that it relies on to manage or monitor the aging of long-lived, passive components and structures.

In LRA Section 3, the applicant provided the results of the AMRs for those structures and components that were identified in License Renewal Application (LRA) Section 2 as being within the scope of license renewal and subject to an AMR.

3.0 Applicant's Use of the Generic Aging Lessons Learned Report

In preparing the LRA, the applicant credited NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," dated July 2001. The GALL Report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the extended period of operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components for license renewal without change. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that the programs at its facility correspond to those reviewed and approved in the GALL Report.

The purpose of the GALL Report is to provide the staff with a summary of staff-approved AMPs to manage or monitor the aging of structures and components 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 also serves as a reference for applicants and staff reviewers to quickly identify those AMPs and activities that the staff determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies (1) systems, structures and components (SSCs), (2) structure and component (SC) materials, (3) the environments to which the SCs are exposed, (4) the aging effects associated with the materials and environments, (5) the AMPs that are credited with managing or monitoring the aging effects, and (6) recommendations for further applicant evaluations of aging management for certain component types.

To determine whether using the GALL Report would improve the efficiency of the license renewal review, the staff conducted a demonstration project to exercise the GALL Report process and to determine the format and content of a safety evaluation based on this process. The results of the demonstration project confirmed that the GALL process will improve the efficiency and effectiveness of the LRA review, while maintaining the staff's focus on public health and safety. NUREG-1800, “Standard Review Plan for the Review of License Renewal Applications,” dated April 2001 (SRP-LR), was prepared based on both the GALL Report model and lessons learned from the demonstration project.

The staff performed its review in accordance 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 guidance provided in SRP-LR, and the guidance provided in the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected aging management reviews and associated AMPs, as described in the “Audit Plan For License Renewal Application Aging Management Programs Aging Management Review Results, Brunswick Steam Electric Plant, Units 1 and 2,” dated December 23, 2004 (ADAMS ML050110445). The onsite audits and reviews are designed to maximize the efficiency of the staff’s review of the LRA. The need for formal correspondence between the staff and the applicant is reduced, and the result is an improvement in the review’s efficiency. In addition, the applicant could respond to questions, and the staff could readily evaluate the applicant’s responses.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that followed the standard LRA format, as agreed to by the Nuclear Energy Institute (NEI) and the Nuclear Regulatory Commission (NRC) (NEI letter dated April 7, 2003). This revised LRA format incorporates lessons learned from the staff’s reviews of the previous five LRAs. These previous applications used a format developed from information gained during a staff and NEI demonstration project that was conducted to evaluate the use of the GALL Report in the staff’s review process.

The organization of LRA Section 3 parallels Chapter 3 of the SRP-LR. The AMR results information in LRA Section 3 is presented in the following two table types:

- Table 1: Table 3.x.1 – where “3” indicates the LRA section number; “x” indicates the subsection number from the GALL Report; and “1” indicates that this is the first table type in LRA Section 3.
- Table 2: Table 3.x.2-y – where “3” indicates the LRA section number; “x” indicates the subsection number from the GALL Report; “2” indicates that this is the second table type in LRA Section 3; and “y” indicates the system table number.

The content of the previous applications and the Brunsick Steam Electric Plant (BSEP) application is essentially the same. The intent of the revised format used for the BSEP application was to modify the tables in Chapter 3 to provide additional information that would assist the staff in its review. In Table 1, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In Table 2, the applicant identified the linkage between the scoping and screening results in Chapter 2 and the AMRs in Chapter 3.

3.0.1.1 Overview of Table 1

Table 3.x.1 (Table 1) provides a summary comparison of how the facility aligns with the corresponding tables of the GALL Report, Volume 1. The table is essentially the same as Tables 1 through 6 provided in the GALL Report, Volume 1, except that the "Type" column has been replaced by an "Item Number" column, and the "Item Number in GALL" column has been replaced by a "Discussion" column. The "Item Number" column provides the reviewer with a means to cross-reference from Table 2 to Table 1. The "Discussion" column is used by the applicant to provide clarifying and amplifying information. The following are examples of information that might be contained in this column:

- further evaluation recommended – information or reference to where that information is located
- the name of a plant-specific program being used
- exceptions to the GALL Report assumptions
- a discussion of how the line is consistent with the corresponding line item in the GALL Report when this may not be intuitively obvious
- a discussion of how the item is different from the corresponding line item in the GALL Report (e.g., when an exception taken to an AMP is listed in the GALL Report)

The format of Table 1 allows the staff to align a specific Table 1 row with the corresponding GALL Report, Volume 1, table row so that the consistency can be easily checked.

3.0.1.2 Overview of Table 2

Table 3.x.2-y (Table 2) provides the detailed results of the AMRs for those components identified in LRA Section 2 as being subject to an AMR. The LRA contains a Table 2 for each of the components or systems within a system grouping (e.g., reactor coolant systems, engineered safety features, auxiliary systems, etc.). For example, the engineered safety feature's (ESF's) group contains tables specific to the containment spray system, containment isolation system, and emergency core cooling system. Table 2 consists of the following nine columns:

(216) Component Type – The first column identifies the component types from LRA Section 2 that are subject to aging management review. The component types are listed in alphabetical order.

(217) Intended Function – The second column contains the license renewal intended functions (including abbreviations where applicable) for the listed component types. Definitions and abbreviations of intended functions are contained within the Intended Functions table of LRA Section 2.

(218) Material – The third column lists the particular materials of construction for the component type.

(219) Environment – The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated

and a list of these environments is provided in the Internal Service Environments and External Service Environments tables of LRA Section 3.

(220) Aging Effect Requiring Management – The fifth column lists aging effects requiring management (AERMs). As part of the aging management review process, the applicant determined any AERM for each combination of material and environment.

(221) Aging Management Programs – The sixth column lists the AMPs that the applicant used to manage the identified aging effects.

(222) GALL Volume 2 Item – The seventh column lists the GALL Report item(s) that the applicant identified as being similar to the AMR results in LRA. The applicant compared each combination of component type, material, environment,AERM, and AMP in SER Table 2 to the items in the GALL Report. If there were no corresponding items in the GALL Report, the applicant left the column blank. In this way, the applicant identified the AMR results in the LRA tables that corresponded to the items in the GALL Report tables.

(223) Table 1 Item – The eighth column lists the corresponding summary item number from Table 1. If the applicant identifies AMR results in Table 2 that are consistent with the GALL Report, then the associated Table 3.x.1 line summary item number should be listed in Table 2. If there is no corresponding item in the GALL Report, then column eight is left blank. That way, the information from the two tables can be correlated.

(224) Notes – The ninth column lists the corresponding notes that the applicant used to identify how the information in Table 2 aligns with the information in the GALL Report. The notes identified by letters were developed by a Nuclear Energy Institute working group and will be used in future license renewal applications. Any plant-specific notes are identified by a number and provide additional information concerning the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

The staff conducted the following three types of evaluations of the AMRs and associated AMPs:

(1) For items that the applicant stated were consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency with the GALL Report.

(2) For items that the applicant stated were consistent with the GALL Report with exceptions and/or enhancements, the staff conducted either an audit or a technical review of the item to determine consistency with the GALL Report. In addition, the staff conduct either an audit or a technical review of the applicant's technical justification for the exceptions and the adequacy of the enhancements.

(3) For other items, the staff conducted a technical review per 10 CFR 54.21(a)(3).

The staff performed an onsite audit and technical review of the license renewal applicant's AMPs and AMRs during the weeks of January 10, 2005, and February 7, 2005. These audit and technical reviews are to determine whether the effects of aging on structures and components can be adequately managed so that their intended functions can be maintained consistently with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Detailed results of the staff's onsite audit are documented in "Audit and Review Report - Plant Aging Management Reviews and Programs - Brunswick Steam Electric Plant, Units 1 and 2" (Audit and Review Report), dated June 21, 2005.

3.0.2.1 Review of AMPs

For those AMPs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify that the applicant's AMPs were consistent with the AMPs in the GALL Report. For each AMP that had one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the AMP, as modified, would adequately manage the aging effect(s) for which it was credited.

For AMPs that were not evaluated in the GALL Report, the staff performed a full review to determine the adequacy of the AMPs. The staff evaluated the AMPs against the following ten (10) program elements defined in SRP-LR Appendix A.

(1) Scope of the Program – Scope of the program should include the specific structures and components subject to an AMR for license renewal.

(2) Preventive Actions – Preventive actions should prevent or mitigate aging degradation.

(3) Parameters Monitored or Inspected – Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended functions(s).

(4) Detection of Aging Effects – Detection of aging effects should occur before there is a loss of structure or component intended functions(s). This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new/one-time inspections to ensure a timely detection of aging effects.

(5) Monitoring and Trending – Monitoring and trending should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.

(6) Acceptance Criteria – Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

(7) Corrective Actions – Corrective actions, including root cause determination and prevention of recurrence, should be timely.

(8) Confirmation Process – Confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) Administrative Controls - Administrative controls should provide a formal review and approval process.

(10) Operating Experience – Operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) and (10) are documented in the Audit and Review Report and are summarized in SER Section 3.0.3.

The staff reviewed the applicant's Corrective Action Program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the Corrective Action Program included assessment of the following program elements: (7) corrective actions, (8) confirmation process, and (9) administrative controls.

The staff reviewed the updated final safety analysis report (UFSAR) supplement for each AMP to determine if it provided an adequate description of the program or activity, as required by 10 CFR 54.21(d).

3.0.2.2 Review of AMR Results

LRA Table 2 contains information concerning whether or not the AMRs align with the AMRs identified in the GALL Report. For a given AMR in Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP for a particular component type within a system. The Table 2 AMRs that correlate with an AMR in the GALL report are identified by a reference item number in column seven called, "GALL, Volume 2 Item." The staff also conducted onsite audits to verify the correlation.

A blank column seven indicates that the applicant was unable to locate an appropriate corresponding combination in the GALL Report. The staff conducted a technical review of these combinations that were not consistent with the GALL Report.

The next column, column eight, "Table 1 Item," provides a reference number that indicates the corresponding row in Table 1. As discussed above, Table 1 provides a summary comparison of how the facility aligns with the corresponding tables of the GALL Report, Volume 1.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR, for the AMRs and associated AMPs that it reviewed, the staff also reviewed the UFSAR supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In performing its review, the staff relied heavily on the LRA, the LRA supplements, the SRP-LR, and the GALL Report. Also, during the onsite audit, the staff examined the applicant's justification, as documented in the staff's Audit and Review Report, to verify that the applicant's activities and programs will adequately manage the effects of aging on SSCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the GALL Report AMP that the applicant claimed its AMP was consistent with (if applicable) and the SSCs for managing or monitoring aging. The section of the SER, in which the staff's evaluation of the program is documented, is also provided.

Table 3.0.3-1 BSEP's Aging Management Programs

BSEP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Existing AMPs				
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (B.2.1)	Consistent	XI.M1	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.1.1
Water Chemistry Program (B.2.2)	Consistent with exceptions	XI.M2	Reactor Vessel, Internals, and Reactor Coolant System; Engineered Safety Features Systems; Auxiliary Systems; Steam and Power Conversion Systems; Containments, Structures, and Component Supports	3.0.3.2.1
Reactor Head Closure Studs Program (B.2.3)	Consistent	XI.M3	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.1.2
BWR Stress Corrosion Cracking Program (B.2.4)	Consistent	XI.M7	Reactor Vessel, Internals, and Reactor Coolant Systems; Engineered Safety Features; Auxiliary Systems; Steam and Power Conversion System	3.0.3.1.3
Flow-Accelerated Corrosion Program (B.2.5)	Consistent with exception and enhancement	XI.M17	Steam and Power Conversion Systems	3.0.3.2.2
Bolting Integrity Program (B.2.6)	Consistent with exceptions and enhancement	XI.M18		3.0.3.2.3

BSEP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Open-Cycle Cooling Water System Program (B.2.7)	Consistent with enhancements	XI.M20	Auxiliary Systems; Steam and Power Conversion Systems	3.0.3.2.4
Closed-Cycle Cooling Water System Program (B.2.8)	Consistent with enhancements	XI.M21	Reactor Vessel, Internals, and Reactor Coolant System; Engineered Safety Features Systems; Auxiliary Systems; Steam and Power Conversion Systems; Containments, Structures, and Component Supports	3.0.3.2.5
Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.9)	Consistent with enhancements	XI.M23	Auxiliary Systems	3.0.3.2.6
Fire Protection Program (B.2.10)	Consistent with exceptions	XI.M26	Auxiliary Systems; Containments, Structures, and Component Supports	3.0.3.2.7
Fire Water System Program (B.2.11)	Consistent with enhancements	XI.M27	Auxiliary Systems; Containments, Structures, and Component Supports	3.0.3.2.8
Fuel Oil Chemistry Program (B.2.13)	Consistent with exceptions and enhancements	XI.M30	Auxiliary Systems	3.0.3.2.9
Reactor Vessel Surveillance Program (B.2.14)	Consistent with enhancement	XI.M31	Reactor Vessel, Internals, and Reactor Coolant System	3.0.3.2.10
ASME Section XI, Subsection IWE Program (B.2.18)	Consistent	XI.S1	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.1.5
ASME Section XI, Subsection IWL Program (B.2.19)	Consistent with exception	XI.S2	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.2.14
ASME Section XI, Subsection IWF Program (B.2.20)	Consistent with enhancement	XI.S3	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.2.15

BSEP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
10 CFR Part 50, Appendix J Program (B.2.21)	Consistent	XI.S4	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.1.6
Masonry Wall Program (B.2.22)	Consistent with enhancement	XI.S5	Containments, Structures, and Component Supports	3.0.3.2.16
Structures Monitoring Program (B.2.23)	Consistent with enhancements	XI.S6	Containments, Structures, and Component Supports	3.0.3.2.17
Protective Coating Monitoring and Maintenance Program (B.2.24)	Consistent with exceptions and enhancements	XI.S8		3.0.3.2.18
Reactor Coolant Pressure Boundary Fatigue Monitoring Program (B.3.1)	Consistent with exception and enhancements	XI.M1	Reactor Vessel, Internals, and Reactor Coolant System; Containments, Structures, and Component Supports	3.0.3.2.20
Environmental Qualification (EQ) Program (B.3.2)	Consistent	X.E1	Electrical Components	3.0.3.1.9
Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Plant Specific			3.0.3.3.1
Systems Monitoring Program (B.2.29)	Plant Specific			3.0.3.3.2
Preventive Maintenance Program (B.2.30)	Plant Specific			3.0.3.3.3
Fuel Pool Girder Tendon Inspection Program (B.2.32)	Plant Specific			3.0.3.3.5
New AMPs				
Aboveground Carbon Steel Tanks Program (B.2.12)	Consistent	XI.M29	Auxiliary Systems	3.0.3.1.4

BSEP's AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures That Credit the AMP	Staff's SER Section
One-Time Inspection Program (B.2.15)	Consistent with exceptions and enhancement	XI.M32	Reactor Vessel, Internals, and Reactor Coolant Systems; Engineered Safety Features; Auxiliary Systems; Steam and Power Conversion Systems; Containment, Structures, and Component Supports	3.0.3.2.11
Selective Leaching of Materials Program (B.2.16)	Consistent with exceptions	XI.M33	Reactor Vessel, Internals, and Reactor Coolant Systems; Engineered Safety Feature Systems; Auxiliary Systems	3.0.3.2.12
Buried Piping and Tanks Inspection Program (B.2.17)	Consistent with exceptions	XI.M34	Engineered Safety Feature Systems; Auxiliary Systems	3.0.3.2.13
Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.25)	Consistent	XI.E1	Electrical Components	3.0.3.1.7
Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (B.2.26)	Consistent with exceptions	XI.E2	Electrical and Instrumentation and Controls	3.0.3.2.19
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.27)	Consistent	XI.E3		3.0.3.1.8
Phase Bus Aging Management Program (B.2.31)	Plant Specific			3.0.3.3.4

3.0.3.1 AMPS That Are Consistent with the GALL Report

In LRA Appendix B, the applicant identified that the following AMPs were consistent with the GALL Report:

- ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program (B.2.1)
- Reactor Head Closure Studs Program (B.2.3)
- BWR Stress Corrosion Cracking Program (B.2.4)
- Aboveground Carbon Steel Tanks Program (B.2.12)
- ASME Section XI, Subsection IWE Program (B.2.18)
- 10 CFR Part 50, Appendix J Program (B.2.21)
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.25)
- Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.27)
- Environmental Qualification (EQ) Program (B.3.2)

3.0.3.1.1 ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.1, “ASME Section XI, Inservice Inspection (ISI), Subsections IWB, IWC and IWD Program.” In the LRA, the applicant stated that this is an existing program that is consistent with GALL AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.”

This program consists of periodic volumetric, surface, and/or visual examination, and leakage test of Class 1, 2, and 3 pressure-retaining components and their integral attachments to detect degradation and determine appropriate corrective actions. The program was developed and prepared to meet the ASME Code, Section XI, 1989 Edition (no Addenda) and is subject to the limitations and modifications of 10 CFR 50.55a, with the exception of design and access provisions and pre-service examination requirements. BSEP is currently operating in accordance with the “Third Inspection Interval ISI Program Plan for Class 1, 2, and 3 Components and Their Supports.”

Certain inspection requirements have been modified by the BSEP Risk Informed Inservice Inspection (RI-ISI) Program presented in Electric Power Research Institute (EPRI) Topical Report, TR-112657. The RI-ISI Program is described in a BSEP submittal, dated April 20, 2001, and in the corresponding NRC staff SER, dated November 28, 2001.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's Audit and Review Report, which provided an assessment of the AMP elements' consistency with GALL AMP XI.M1.

During the audit, the staff noted that, in the program description section of ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program, the applicant stated that the RI-ISI Program was discussed in EPRI Topical Report TR-112657. The staff informed the applicant that the NRC does not recognize or consider a currently approved RI-ISI Program (or any other currently approved relief requests) in evaluating an applicant's claim of consistency with the GALL Report because the RI-ISI Program and relief request are not part of the technical basis for the ASME ISI Program in the GALL Report. In addition, the currently approved RI-ISI Program and relief requests are only effective in the 10-year ISI Interval which means that they will not be applicable during the period of extended operation.

As documented in the staff's Audit and Review Report, the applicant stated that it will comply with 10 CFR 50.55a for the extended period of operation. The applicant also stated that the ASME Section XI ISI program description, which will be integrated into the USFAR supplement, will be revised to omit reference to the RI-ISI as a part of the program, along with information concerning a specific inspection interval. The revised UFSAR wording will read as follows:

> The ASME Section XI, Inservice Inspection, Subsection IWB, IWC, and IWD program consists of periodic volumetric, surface, and/or visual examination of components in accordance with applicable requirements and provisions of 10 CFR 50.55a.

The staff reviewed and determined that the applicant's response is acceptable on the basis that currently approved relief requests and approved Code cases will not be carried over into the period of extended operation.

In reviewing the scope of this program, the staff noted that, in LRA Tables 3.2.2-3, 3.2.2-5, and 3.2.2-7, the applicant credits the ASME Section XI, Inservice Inspection, Subsection IWB, IWC, and IWD Program, along with the Water Chemistry Program, for aging management of small-bore piping. However, small-bore piping is exempt from inspection under the ASME ISI program; therefore, this AMP would not be appropriate for inspecting these components. The staff asked the applicant to provide details of the program used to inspect small-bore piping (including pipe, fittings, and branch connections) for loss of material and cracking.

As documented in the staff's Audit and Review Report, the applicant stated that it will use the Water Chemistry Program and the ASME Section XI, Inservice Inspection, Subsection IWB, IWC, and IWD Program (for leakage inspections) for aging management of small-bore piping. In addition, the One-Time Inspection Program will be utilized for verification of program effectiveness. The staff determined that the applicant's response is acceptable on the basis that the approach is consistent with the GALL Report.

Operating Experience. In LRA Section B.2.1, the applicant stated that this program is implemented and maintained in accordance with the general requirements for engineering programs. This provides assurance that the program is effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; qualified personnel are assigned as program managers, and are given authority and responsibility to implement the program; and adequate resources are committed to program activities.

The applicant stated that a search of condition reports and ISI history, including self-assessments and inspections, was conducted and showed the ASME Section XI ISI program to be critically monitored and effective. Based on these results, the plant's Operating Experience Program provides evidence that the program and maintenance practices are ensuring the continuing integrity of the ISI Class 1, 2, and 3 components.

The staff reviewed results of the operating experience review and selected BSEP self-assessment and inspection reports, as documented in the staff's Audit and Review Report, to ascertain the effectiveness of the ISI program. The applicant's self-assessment team identified no issues related to ISI program management or program implementation.

In addition to the self assessment, the staff reviewed a report documenting an inspection performed by staff at BSEP on March 20, 2004. As part of that effort, the staff inspectors reviewed ISI procedures, observed in-process ISI work activities, and reviewed selected ISI records. The inspectors observed portions of ultrasonic tests (UTs) on four welds to verify they were being performed acceptably. No findings of significance related to the ISI program were identified. The staff concluded that the documents reviewed support the applicant's assessment of program effectiveness.

On the basis of its review of the above industry and plant-specific operating experience and on discussions with the applicant's technical staff, the staff team concluded that ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.1, the applicant provided the UFSAR supplement for the ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Reactor Head Closure Studs Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.3, "Reactor Head Closure Studs Program." In the LRA, the applicant stated that this is an existing program that is consistent with GALL AMP XI.M3, "Reactor Head Closure Studs."

In the LRA, the applicant stated that this program is credited for aging management of reactor head closure studs and stud components. The closure studs, nuts, bushings, and washers are included within the scope of the ASME Section XI inservice Inspection, Subsections IWB, IWC, and IWD Program. While BSEP is not committed to regulatory guide (RG) 1.65, the reactor head closure studs program preventive measures are consistent with the recommendations of the regulatory guide. Aging effects/mechanisms of concern are cracking due to stress corrosion cracking (SCC), and loss of material due to:(1) general corrosion, (2) crevice corrosion, and (3) pitting corrosion.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's Audit and Review Report, which provided an assessment of the AMP elements' consistency with GALL AMP XI.M3.

From a review of the applicant's documentation, the staff determined that, while BSEP is not committed to regulatory guide (RG) 1.65, the reactor head closure studs program preventive measures are consistent with the recommendations of the regulatory guide. Also, preventive measures consistent with the recommendations of the RG, such as inspections (UT, magnetic particle test (MT)/penetrant test (PT), etc.), and periodic lubrication with a corrosion inhibitor, are performed.

The ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program uses a combination of visual, surface, and volumetric examinations of the studs, nuts, bushings, washers, and stud holes (including the flange threads) to detect discontinuities and flaws. Visual VT-2 examination of the entire reactor coolant pressure boundary to detect evidence of leakage from pressure-retaining components is routinely performed during pressure tests as required by the ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program.

Operating Experience. In the LRA, the applicant stated that this program is implemented through the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program which monitors the condition of the closure studs and stud components. The Reactor Head Closure Studs Program is implemented and maintained in accordance with the general requirements for engineering programs. This provides assurance that the program is effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; qualified personnel are assigned as program managers, and are given authority and responsibility to implement the program; and adequate resources are committed to program activities.

The applicant further stated that a search of condition reports and ISI history was conducted, and no reports documenting deficiencies or problems with vessel head closure studs or stud components, or the Reactor Head Closure Studs Program, were found. Based on these results, the operating experience provides evidence that the program and maintenance practices are ensuring the continuing integrity of the reactor head closure studs and stud components.

Additionally, the applicant stated that, per ASME Section XI ISI requirements, the reactor pressure vessel studs are inspected every 10 years and the next series of inspections will be performed in 2007 and 2008.

UFSAR Supplement. In LRA Section A.1.1.3, the applicant provided the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Reactor Head Closure Studs Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 BWR Stress Corrosion Cracking Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.4, "BWR Stress Corrosion Cracking Program." In the LRA, the applicant stated that this is an existing program that is consistent with GALL AMP XI.M7, "BWR Stress Corrosion Cracking."

In the LRA, the applicant stated that the Boiling Water Reactor (BWR) Stress Corrosion Cracking Program manages intergranular stress corrosion cracking (IGSCC) in reactor coolant pressure boundary components made of stainless steel. The program includes:

- Preventive measures to mitigate SCC, including IGSCC. The comprehensive program outlined in NRC Generic Letter (GL) 88-01, NUREG-0313, "NRC Position on Intergranular Stress Corrosion Cracking in BWR Austenitic Stainless Steel Piping," NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," Revision 2, and in the staff-approved BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," has been implemented. This comprehensive program addresses the mitigating measures for SCC and IGSCC. Preventive methodologies include piping replacement with IGSCC resistant stainless steel. Preventive measures have included heat sink welding, induction heating, and mechanical stress improvement. The Water Chemistry Program controls water chemistry within parameters that prevent, minimize, and mitigate IGSCC.
- Inspection and flaw evaluation to monitor SCC (including IGSCC) and its effects. The staff-approved BWRVIP-75 report allows for modifications of inspection scope in the GL 88-01 program. This program detects degradation due to SCC (including IGSCC). The BWR Stress Corrosion Cracking Program is consistent with NUREG-0313, BWRVIP-75, and GL 88-01 and its Supplement 1.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s Audit and Review Report, which provided an assessment of the AMP elements' consistency with GALL AMP XI.M7.

The staff noted that the program element for preventive actions for GALL AMP XI.M7 states that BWR water chemistry control should be performed in accordance with Boiling Water Reactor Vessel and Internals Project (BWRVIP)-29, which references the 1993 version of EPRI TR-103515, “BWR Water Chemistry Guidelines.” However, the program description for the BWR Stress Corrosion Cracking Program states that the Water Chemistry Program is based on BWRVIP-79, which references the 2000 revision of EPRI TR-103515-R2 and uses hydrogen water chemistry (HWC) to control both detrimental impurities and crack initiation and growth. This difference is addressed in the evaluation of an exception to the Water Chemistry Program, which is discussed in SER Section 3.0.3.2.1.

Operating Experience. In the LRA, the applicant stated that BSEP, as well as most of the BWR fleet of reactors, has experienced IGSCC of austenitic stainless steel piping. The implementation of the comprehensive program outlined in GL 88-01, NUREG-0313, and in the staff-approved BWRVIP-75, in conjunction with the Water Chemistry Program, has been effective in managing SCC (including IGSCC). The BWR Stress Corrosion Cracking Program has been shown to be effective at identifying the aging effect of cracking due to SCC (including IGSCC) so that repairs or replacements are implemented prior to failure.

The applicant further stated that since the implementation of this program, structural integrity has been maintained by ensuring that aging effects were discovered and repaired/replaced before the loss of intended function of the component.

The staff recognized that the Corrective Action Program, which captures internal and external plant operating experience issues, will ensure that operating experience is reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging are adequately managed.

UFSAR Supplement. In LRA Section A.1.1.4, the applicant provided the UFSAR supplement for the BWR Stress Corrosion Cracking Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s BWR Stress Corrosion Cracking Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 Aboveground Carbon Steel Tanks Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.12, “Aboveground Carbon Steel Tanks Program.” In the LRA, the applicant stated that this is a new program that is consistent with GALL AMP XI.M29, “Aboveground Carbon Steel Tanks.”

In the LRA, the applicant stated that the purpose of this program is to perform inspections of tanks to provide reasonable assurance that the components perform their intended function consistent with the CLB throughout the period of extended operation (see Commitment Item #8). The program manages aging effects of loss of material for external surfaces and inaccessible locations of the main fuel oil storage tank, condensate storage tanks and fire protection water storage tank. These tanks are constructed of carbon steel.

The applicant also stated that this program relies on periodic system walkdowns and inspections to monitor the condition of these tanks. This includes an assessment of the condition of tank surfaces protected by paint or coating and the caulking at the concrete foundation interface. The paint is not credited with performing a preventive function for aging management. For inaccessible surfaces, such as the tank bottom, one-time thickness measurements will be performed from inside the tank to assess the tank bottom condition. Using one-time inspections of tank bottoms ensures that degradation or significant loss of material will not occur in inaccessible locations. In addition, the condensate storage tanks and fire protection water storage tank will be subject to a one-time inspection of all interior surfaces. The Systems Monitoring Program will provide guidance to ensure that the external surfaces of the subject tanks are periodically inspected.

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M29.

The staff determined that the applicant plans to rely on periodic inspections conducted in accordance with 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and the Systems Monitoring Program, which monitors tank degradation. The applicant will conduct periodic external inspections, to ensure the pressure-retaining boundary intended function is maintained, and one-time inspections of internal surfaces. The staff concluded that the applicant’s Aboveground Carbon Steel Program provides reasonable assurance that the aging effects will be managed such that the tanks within the scope of the program will continue to perform their intended function consistent with the CLB throughout the period of extended operations.

Operating Experience. In the LRA, the applicant stated that for the main fuel oil storage tank, nondestructive examination (NDE) testing has been conducted on the emergency fire pump diesel fuel oil storage tank and each of the four diesel generators (DGs) 4-day fuel oil storage tanks. Problems relating to tank wall thickness degradation were not found on the subject tanks. This operating experience highlights the effectiveness of the Fuel Oil Chemistry Program in minimizing the loss of material within the fuel oil system.

The LRA also states that during inside-condensate storage tank (CST) inspections, corrosion products and coating film degradation were noted, and the shell wall thickness readings were acceptable. The shell plates have experienced negligible corrosion. On the CST bottom plates, minor corrosion indications were noted on both the Unit 1 and Unit 2 tanks and evaluated as acceptable. In addition, the exterior of each CST has been inspected. External tank surface corrosion was identified on small portions of the shell wall and evaluated as acceptable.

The LRA further states that the fire protection water storage tank inspection determined that the tank is structurally sound. The tank foundation has some minor cracking, and the interior coating has some primer degradation; both conditions have been evaluated as acceptable.

In its procedures, the applicant stated that it provides guidance for using, sharing, and evaluating operating experience at other Nuclear Generation Group (NGG) sites as well as promoting the identification and transfer of lessons learned by the industry. The staff reviewed the applicant’s procedure and determined that the procedure is acceptable.

UFSAR Supplement. In LRA Section A.1.1.12, the applicant provided the UFSAR supplement for the Aboveground Carbon Steel Tanks Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s Aboveground Carbon Steel Tanks Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 ASME Section XI, Subsection IWE Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.18, “ASME Section XI, Subsection IWE Program.” In the LRA, the applicant stated that this is an existing program that is consistent with GALL AMP XI.S1, “ASME Section XI, Subsection IWE.”

In the LRA, the applicant stated that this program consists of periodic inspections of steel containment structures. The program is in accordance with the ASME Code, Section XI, Subsection IWE, 1992 Edition, with the 1992 Addenda, as modified by 10 CFR 50.55a. This program is credited for the aging management of (1) steel liners for the concrete containment and their associated integral attachments, (2) containment personnel and equipment airlocks, hatches, and drywell head, (3) seals, gaskets, and moisture barriers, (4) torus liner, downcomers, and vent header, and (5) pressure-retaining bolting.

The applicant also stated that the primary inspection method for the steel containment liner and its integral attachments is visual examination. Limited volumetric examinations utilizing ultrasonic thickness measurements are implemented as applicable.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provided an assessment of the AMP elements' consistency with GALL AMP XI.S1.

Operating Experience. In the LRA, the applicant stated that the ASME Section XI, Subsection IWE Program is implemented and maintained in accordance with the general requirements for engineering programs. This provides assurance that the programs (1) are effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; (2) have qualified personnel assigned as program managers, with authority and responsibility to implement the program; (3) have adequate resources committed to program activities; and (4) are managed in accordance with plant administrative controls.

The applicant also stated that the review of plant-specific operating experience has identified numerous assessments, performed on both a plant-specific and corporate basis, dealing with program development, effectiveness, and implementation. The ASME Section XI, Subsection IWE Program is continually being upgraded based upon industry and plant-specific experience. Additionally, plant operating experience is shared between Progress Energy sites through regular peer group meetings, a common corporate sponsor, and outage participation of program managers from other Progress Energy sites.

The staff asked the applicant to describe any augmented inspections that are currently being performed in accordance with IWE requirements. The applicant stated that the augmented inspections are located in Brunswick Nuclear Plant (BNP)-TR-002, Appendix F.

Based on review of the applicant's augmented inspection procedure and on follow-up discussions with the applicant's technical staff, the staff concluded that the applicant has appropriately considered the need for augmented inspections, in accordance with IWE requirements. The parameters monitored for the drywell and suppression chamber steel liners currently include "bulging" of the liner plate. Observation of bulging led to the past discovery of through-wall corrosion of the drywell liner plate at two locations. The applicant has repaired these locations to restore the liner to its design-basis condition. The root cause analyses for both locations concluded that the corrosion initiated from the outside surface of the liner plate, where construction debris was trapped between the liner plate and the concrete containment wall.

UFSAR Supplement. In LRA Section A.1.1.18, the applicant provided the UFSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's ASME Section XI, Subsection IWE Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 10 CFR Part 50, Appendix J Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.21, "10 CFR Part 50, Appendix J Program." In the LRA, the applicant stated that this is an existing program that is consistent with GALL AMP Section XI.S4, "10 CFR Part 50, Appendix J."

In the LRA, the applicant stated that this program is structured in accordance with the requirements of 10 CFR Part 50, Appendix J, and assures the required performance-based leak testing of the containment and its penetrations. The applicant also stated that the program is the acceptable method for verifying, through testing, the management of aging effects for containment integrity as documented in the GALL Report. The 10 CFR Part 50, Appendix J Program is applicable to the leakage testing portion of aging management for the BSEP containment and its penetrations. The program is in accordance with Option B (performance-based leak testing) of 10 CFR Part 50, Appendix J and the guidelines contained in RG 1.163, September 1995, and NEI 94-01, "Industry Guideline for Implementing Performance Based Option of 10 CFR Part 50, Appendix J."

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S4.

The GALL Report specifies that the scope of the containment leakage rate test (LRT) program include all pressure-retaining components. Type A tests are performed to measure the overall primary containment integrated leakage rate test (ILRT) and Type B tests measure local leakage rates across each pressure-containing or leakage-limiting boundary for containment penetrations. The applicant stated that the containment LRT program includes all pressure-retaining components.

The applicant stated that BSEP uses the Option B testing program, which allows a variable risk-informed testing schedule for Types A and B testing. The staff inquired whether Appendix J, Type C testing is credited for aging management for license renewal. The applicant clarified during the audit and review that 10 CFR Part 50, Appendix J, Type C, testing of containment isolation valves is also performed in accordance with Option B; however, it is not a credited aging management activity for license renewal. The staff determined that the applicant's program scope is in accordance with the GALL Report since other AMPs are credited for managing the applicable valves. The GALL Report does not require that Type C testing be credited for license renewal, provided other appropriate AMPs are credited.

The GALL Report specifies that leakage rates are to be monitored through containment shells, containment liners, and associated welds, penetrations, fittings and other access openings. The staff reviewed plant procedures, as documented in the staff's Audit and Review Report, and determined that it defines the administrative requirements and controls (test preparation, approval, performance and evaluation) for the 10 CFR Part 50, Appendix J, ILRT Option B and the ASME Section XI valve leak rate tests. The staff determined that the parameters monitored and inspected under this program are in accordance with applicable the GALL Report requirements.

As discussed in the GALL Report, leakage rate calculations do not provide indications of the initiation of aging degradation or reduced containment capacity under other types of loads (such as seismic). The applicant stated that the primary containment inspection is a prerequisite to the ILRT and assures the early detection of aging degradation of the containment barrier. At BSEP, implementation of containment ISI is performed under ASME Section XI, Subsection IWE and ASME Section XI, Subsection IWL Programs (LRA AMPs B.2.18 and 19, respectively). The staff reviewed plant procedures and determined that they specify the primary containment inspection before ILRT performance. The staff determined that the containment testing performed under this program, in conjunction with ASME Section XI, Subsection IWE and ASME Section XI, Subsection IWL Programs, provide a program for the detection of aging effects in accordance with the GALL Report requirements. The staff also reviewed technical specification (TS) Section 5.5.12 for both units and found that it specifies when the tests shall be performed. The staffs determined that the monitoring and trending requirements are in accordance with GALL Report requirements.

The GALL Report states that acceptance rates for leakage tests are defined in the technical specifications. The applicant stated that the BSEP TS Section 5.5.12, identifies the primary containment leakage rate testing program and the leakage rate acceptance criteria. The applicant further stated that the program is in accordance with the guidelines of RG 1.163 September 1995, with the following modifications: (1) compensation for instrument accuracies applied to the primary containment leakage total is in accordance with American National Standards Institute (ANSI)/ANS 56.8-1987 instead of ANSI/ANS 56.8-1994; (2) following air lock door seal replacement, performance of door seal leakage rate testing is conducted with the gap between the door seals pressurized to 10 psig instead of air lock testing at Pa (one newton per square meter) as specified in NEI Guideline 94-01 Revision 0; (3) reduced duration Type A tests may be performed using the criteria and total time method in Bechtel Topical Report BN-TOP Revision 1; (4) performance of Type C leak rate testing of the hydrogen and oxygen monitor isolation valves is not required; (5) performance of Type C leak rate testing of the main steam isolation valves is performed at a pressure less than Pa instead of leak rate testing at Pa as specified in ANSI/ANS 56.8-1994; and, (6) NEI 94-01-1995, Section 9.2.3: a one-time extension of the current 10-year Type A test interval. The staff reviewed the technical specifications for both units and determined that the above modifications are as specified for both units.

Operating Experience. In the LRA, the applicant stated that the 10 CFR Part 50, Appendix J Program is maintained in accordance with BSEP engineering program requirements. This provides assurance that (1) the program is effectively implemented to meet regulatory process and procedure requirements, including periodic reviews; (2) that qualified personnel are assigned as program managers, and are given authority and responsibility to implement the program; and (3) adequate resources are committed to program activities.

The applicant concludes that, based on review of operating history, corrective actions, and self-assessments the 10 CFR Part 50, Appendix J Program is continually monitored and enhanced to incorporate the results of operating experience as such it provides an effective means of ensuring the structural integrity and leak tightness of the containment.

The applicant stated that the results of operating experience for this program are contained in a BSEP calculation, as documented in the staff''s Audit and Review Report, to document a representative sample of those operating events which validate the results of the aging effect evaluations or identify additional aging effects not previously determined by the standard method of aging management review. For this testing, the applicant concluded the following: the expected component degradations identified through testing and inspections prompt timely corrective actions; procedure and program deficiencies were identified during routine program performance which were promptly corrected; and, program findings, weaknesses, and other items for consideration resulted in program improvements.

The staff reviewed several specific self-assessment reports as part of its review. Several program weaknesses were identified and corrected by the applicant, but no component operability concerns were noted. Based on the review of these self-assessments, the staff reviewed and determined that the applicant is adequately performing the testing required in 10 CFR Appendix J, and concludes that there is reasonable assurance that the same will continue to the period of extended operation.

<u>UFSAR Supplement</u>. In LRA Section A.1.1.21, the applicant provided the UFSAR supplement for the 10 CFR Part 50, Appendix J Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's 10 CFR Part 50, Appendix J Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

<u>Summary of Technical Information in the Application</u>. This AMP is described in LRA Section B.2.25, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program." In the LRA, the applicant stated that this is a new program that is consistent with GALL AMP XI.E1 (see Commitment Item #18)."

In the LRA, the applicant stated that this program is credited for aging management of cables and connections not included in the EQ Program. In addition, the applicant stated that accessible electrical cables and connections installed in adverse localized environments are visually inspected at least once every 10 years for cable and connection jacket surface anomalies.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provides an assessment of the AMP elements' consistency with GALL AMP XI.E1.

The staff reviewed those portions of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program for which the applicant claims consistency with GALL AMP XI.E1 and determined that they are consistent with the GALL Report. Furthermore, the staff concluded that the applicant’s electrical cables and connections not subject to 10 CFR 50.49 environmental qualification requirements program provides reasonable assurance that the intended functions of electrical cables and connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture, will be maintained.

Operating Experience. In the LRA, the applicant stated that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program with no operating experience history. However, as noted in the GALL Report, industry operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections have been shown to exist and have been found to produce degradation of insulating materials that is visually observable.

During the audit, the staff asked the applicant how operating experience is captured. The applicant indicated that a plant procedure, as discussed in the staff’s Audit and Review Report, is used to increase personnel’s awareness of plant and industrial operating experience so that lessons learned can be used to adjust its AMP, as necessary. In its procedure, the applicant stated that it provides guidance for using, sharing, and evaluating operating experience at NGG sites as well as for promoting the identification and transfer of lessons learned from industry. The staff reviewed the applicant’s procedure and determined that the procedure is acceptable.

On the basis of its review of the above industry and plant-specific operating experience and on discussions with the applicant's technical staff, the staff concludes that the applicant’s Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.25, the applicant provided the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.27, "Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program." In the LRA, the applicant stated that this is a new program that is consistent with GALL AMP XI.E3, "Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program."

In the LRA, the applicant stated that the Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is credited for managing aging cables that are not included in the EQ Program. In-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, polarization index, or other testing that is state-of-the-art at the time the test is performed. Significant moisture is defined as periodic exposures that last more than a few days (e.g., cable in standing water). Periodic exposures that last less than a few days (e.g., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time. Continuous wetting and continuous energization are not significant for medium-voltage cables that are designed for these conditions (e.g., marine cables).

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP elements' consistency with GALL AMP XI.E3.

In its basis documentation, the applicant stated that no preventive actions are required as part of the Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Periodic actions may be taken to prevent non-EQ medium-voltage cables from being exposed to significant moisture. In addition, the applicant stated that medium-voltage cables for which such actions are taken are not required to be tested.

The staff noted that periodic actions should be taken to minimize cable exposure to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. The above action may not be sufficient to assure that water is not trapped elsewhere in the raceways. Therefore, the in-scope medium-voltage cables exposed to significant moisture and voltage should also be tested to provide an indication of the condition of the conductor insulation. The staff requested that the applicant provide the inspection frequency of the manholes and the testing frequency for the inaccessible medium-voltage cables, or provide technical justification that the inspection and testing are not necessary.

As documented in the staff's Audit and Review Report, the applicant stated that LRA Section A.1.1.27 and the USFAR supplement will be revised to address inspection of the manholes (see Commitment Item #20). Specifically, the inspection frequency of the manholes will be based on actual field data, and will not exceed two years. The testing of the inaccessible medium-voltage cables will be performed at least once every 10 years. The initial tests will be completed before the end of the initial 40-year license term. The staff reviewed the applicant's response and determined that it is acceptable on the basis that it is consistent with the recommendations in the GALL Report.

Operating Experience. In the LRA, the applicant stated that the inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program with no operating experience history. However, as noted in the GALL Report, industry operating experience has shown that cross-linked polyethylene (XLPE) or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. The formation and growth of water trees varies directly with operating voltage. Treeing is much less prevalent in 4KV cables than those operated at 13KV or 33KV. Also, minimizing exposure to moisture minimizes the potential for the development of water treeing.

During the audit, the staff asked the applicant how operating experience is captured. The applicant indicated, as documented in the staff's Audit and Review Report, that a plant procedure is used to increase personnel's awareness of plant and industrial operating experience so that lessons learned can be used to adjust its AMP, as necessary. In its procedure, the applicant stated that it provides guidance for using, sharing, and evaluating operating experience at NGG sites, as well as promoting the identification and transfer of lessons learned by the industry. The staff reviewed the applicant's procedure and determined that the procedure is acceptable.

On the basis of its review of the above industry and plant-specific operating experience, and on discussions with the applicant's technical staff, the staff concluded that the applicant's BSEP AMP B.2.27 will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.27, the applicant provided the UFSAR supplement for the Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program which states that the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is credited for aging management of cables not included in the EQ Program. In-scope, medium-voltage cables exposed to significant moisture and significant voltage, as discussed in the staff's BSEP Audit and Review Report, are tested at least once every 10 years to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, polarization index, or other testing that is state-of-the-art at the time the test is performed.

As documented in the staff's Audit and Review Report, the applicant provided a revision to its UFSAR supplement that addresses inspection and testing for the Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Specifically, the inspection frequency of manholes will be based on actual field data, but not to exceed two years. The testing of the inaccessible medium-voltage cables will be performed at least once every 10 years. The initial tests will be completed before the end of the initial 40-year license term.

The staff reviewed this section and determined that, with the revision, the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Environmental Qualification (EQ) Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.3.2, "Environmental Qualification (EQ) Program." In the LRA, the applicant stated that this is an existing program that is consistent with GALL AMP XI.E1, "Environmental Qualification (EQ)."

In the LRA, the applicant stated that the EQ Program manages component thermal aging, radiation aging, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished or replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are time-limited aging analyses (TLAAs) for license renewal.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff determined that this AMP is consistent with the AMP described in the GALL Report, including the associated operating experience attribute.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP elements' consistency with GALL AMP X.E1.

The staff concluded that the applicant's EQ Program is adequate for managing component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods.

Operating Experience. In the LRA, the applicant stated that its EQ Program has been effective at managing aging effects; operating experience has identified no age-related equipment failures that its program is intended to prevent. As stated in the GALL Report, EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended functions during accident conditions after experiencing the effects of in-service aging. The overall effectiveness of the program is demonstrated by the excellent operating experience for systems and components in the program. In addition, the EQ Program has been and continues to be subject to periodic internal and external assessments that effect continuous improvement.

UFSAR Supplement. In LRA Section A.1.2.3, the applicant provided the UFSAR supplement for the EQ Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's EQ Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 Summary of Conclusions for AMPs That Are Consistent With the GALL Report

During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of these AMPs are documented in the BSEP Audit and Review Report. The staff determined that these AMPs are consistent with the AMPs described in the GALL Report, including the associated operating experience attribute.

During the audit, the staff reviewed selected documents and procedures, as discussed in the staff's BSEP Audit and Review Report (ML051720621), associated with the AMPs identified above. As a result of this review, the staff identified issues for several of the AMPs that were resolved with a docketed response from the applicant. Those issues and their resolutions are discussed above.

On the basis of its review and audit of the applicant's programs, the staff found that those programs for which the applicant claims consistency with AMPs in the GALL report without exceptions or enhancements are consistent with the GALL report.

The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the UFSAR supplements for these AMPs and found that they will provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPS That Are Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant identified that the following AMPs were, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Water Chemistry Program (B.2.2)
- Flow-Accelerated Corrosion Program (B.2.5)
- Bolting Integrity Program (B.2.6)
- Open-Cycle Cooling Water System Program (B.2.7)
- Closed-Cycle Cooling Water System Program (B.2.8)
- Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.9)
- Fire Protection Program (B.2.10)
- Fire Water System Program (B.2.11)
- Fuel Oil Chemistry Program (B.2.13)
- Reactor Vessel Surveillance Program (B.2.14)
- One-Time Inspection Program (B.2.15)
- Selective Leaching of Materials Program (B.2.16)
- Buried Piping and Tanks Inspection Program (B.2.17)
- ASME Section XI, Subsection IWL Program (B.2.19)
- ASME Section XI, Subsection IWF Program (B.2.20)
- Masonry Wall Program (B.2.22)
- Structures Monitoring Program (B.2.23)
- Protective Coating Monitoring and Maintenance Program (B.2.24)
- Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (B.2.26)
- Reactor Coolant Pressure Boundary Fatigue Monitoring Program (B.3.1)

For AMPs that the applicant claimed are consistent with the GALL Report, with exception(s) or enhancement(s), the staff performed an audit to confirm that those attributes or features of the program for which the applicant claimed consistency with the GALL Report were, indeed, consistent. The staff also reviewed the exception(s) and enhancement(s) to the GALL Report to determine whether they are acceptable and adequate. The results of the staff's audit and review is documented in the following sections.

3.0.3.2.1 Water Chemistry Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.2, "Water Chemistry Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions, with GALL AMP XI.M2, "Water Chemistry."

In the LRA, the applicant stated that the main objective of the Water Chemistry Program is to minimize loss of material, cracking, and flow blockage. The Water Chemistry Program is consistent with and relies on monitoring and control of water chemistry based on the latest version of the BWR water chemistry guidelines. This version contains guidelines for reactor water, condensate and feedwater, for control rod drive cooling water, and other systems such as spent fuel pool water. The Water Chemistry Program includes periodic monitoring, control, and mitigation of known detrimental contaminants below the levels known to result in loss of material, cracking, and flow blockage.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exceptions and the associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP's consistency with GALL AMP XI.M2.

During the audit, the staff noted that in the AMP element for "Scope of Program," the applicant stated that the Water Chemistry Program is based on BWRVIP-79, which recommends HWC. However, the applicant stated that BSEP is a normal water chemistry plant. To clarify this discrepancy, the applicant stated, as documented in the staff's Audit and Review Report, that BSEP is an HWC plant. Therefore, the basis document will be revised to reflect this. The staff determined that the applicant's response is acceptable since the use of HWC is consistent with the recommendations in the GALL Report for the "scope of program" program element of this AMP.

In LRA Table 3.3.2-16, the applicant specifies the Water Chemistry Program and the One-Time Inspection Program for managing loss of material for the aluminum demineralized water storage tank. The staff asked the applicant to clarify how aging degradation of the aluminum demineralized water tank will be managed by the Water Chemistry Program.

As documented in the staff's Audit and Review Report, the applicant stated that BSEP AMRs have identified that the demineralized water tank is constructed of aluminum, and potentially susceptible to crevice, pitting, and galvanic corrosion. The applicant had specified the Water Chemistry AMP, augmented by the One-Time Inspection AMP, to address this aging effect. BSEP performs routine internal visual inspections of the demineralized water tank to ensure the tank is not experiencing corrosion. BSEP will credit a combination of the Water Chemistry

Program and the Preventive Maintenance Program to manage these aging effects during the period of extended operation."

The staff determined that the applicant's response is acceptable on the basis that degradation in the demineralized water tank would be observed during periodic inspections through the Preventive Maintenance Program, assuring its structural integrity.

The staff noted that in LRA Table 3.3.2-7, the Water Chemistry Program is credited to manage loss of material for the standby liquid control solution storage tank. However, the sodium pentaborate solution in the tank would likely mask most of the chemistry parameters. When questioned by the staff, the applicant stated that AMRs have identified the potential for corrosion of components in the standby liquid control system (including the storage tank, piping, and valves). The standby liquid control system piping, valves, and storage tank are filled with a solution of high purity sodium pentaborate dissolved in demineralized water. While water chemistry sampling of the standby liquid control system is limited to verifying the concentration of boron, water chemistry monitoring on the demineralized water tank does include stringent controls on parameters such as sulfates, chlorides, conductivity and suspended solids. Since the only source of water for makeup to the system is demineralized water, the benefit of chemistry controls, associated with demineralized water, are extended to the standby liquid control system. The effectiveness of these controls will be verified by implementation of the One-Time Inspection Program, consistent with the application of this program as described in GALL AMP XI.M32. Therefore, a combination of the Water Chemistry Program and One-Time Inspection Program will provide reasonable assurance that the intended functions of the components will be adequately managed for the period of extended operation.

In LRA Section B.2.2, the applicant identified the following exceptions to program elements in the GALL Report. The staff evaluation of the affected GALL Report program elements ("scope of program," "preventive actions," "parameters monitored/inspected," and "monitoring and trending") for the acceptability of the exception is as follows:

<u>Exception 1 - Scope of Program</u>. The GALL Report identifies the following recommendations for the "scope of program" program element associated with the exception taken:

> The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or crack initiation and growth. Water chemistry control is in accordance with the guidelines in BWRVIP-29 (EPRI Report TR-103515) for water chemistry in BWRs; EPRI TR-105714, Rev. 3, for primary water chemistry in PWRs; EPRI TR-102134, Rev. 3, for secondary water chemistry in PWRs; or later revisions or updates of these reports as approved by the staff.

<u>Exception</u>: Though the GALL Report recommends that water chemistry be controlled in accordance with BWRVIP-29 (references the 1993 revision of EPRI Report TR-103515, "BWR Water Chemistry Guidelines"), the Water Chemistry Program is based on the latest version of the BWRVIP Water Chemistry Guidelines (currently BWRVIP-79, which references EPRI Report TR-103515-R2, "BWR Water Chemistry Guidelines," February 2000).

EPRI incorporates new information to develop proactive plant-specific water chemistry programs to minimize IGSCC. EPRI periodically updates the water chemistry guidelines as new information becomes available. The applicant stated that its Water Chemistry Program will be updated as revisions to the guidelines are released. The staff found EPRI TR-103515-R2 acceptable because the program is based on updated industry experience and plant-specific and industry-wide operating experience confirms the effectiveness of the Water Chemistry Program.

The applicant further stated that a review of in-vessel visual examination reports was performed and acceptable results were observed during recent inspections. For example, a crack in jet pump riser "G" RS-1 weld was examined during outages B113R1, B114R1, and B115R1 with no discernible growth noted. Similar results have been found in the examination of other reactor vessel internals components, such as the core spray sparger piping. Also, inspections performed on piping components associated with GL 88-01 (NRC Position on IGSCC in BWR austenitic stainless steel piping), as modified by BWRVIP-75, have also had good results.

The applicant stated that as revisions to the guidelines are released, the Water Chemistry Program will be updated to develop a more proactive program that minimizes age-related degradation.

During the audit, the staff determined that the applicant's response is acceptable since it is consistent with the recommendations provided in the EPRI-recommended HWC program, which is an enhancement to the Water Chemistry Program recommended by the GALL Report. Therefore, the staff concluded that this exception is acceptable.

<u>Exception 2 - Preventive Actions</u>. The GALL Report identifies the following recommendations for the "preventive actions" program element associated with the exception taken:

> The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice and pitting corrosion and crack initiation and growth caused by SCC. For BWRs, maintaining high water purity reduces susceptibility to SCC.

<u>Exception</u>: The Water Chemistry Program is additionally credited with managing loss of material due to galvanic corrosion and flow blockage due to fouling.

In the LRA, certain AMRs credit this program for mitigating loss of material due to galvanic corrosion or flow blockage due to fouling. Galvanic corrosion is managed using the same methods applied for crevice corrosion, general corrosion, pitting corrosion, and SCC. The parameter limits in effect are based on the latest version of the BWR water chemistry guidelines. These parameters include, but are not limited to, chloride, specific conductivity, sulfate, nitrite, tolyltriazole, dissolved oxygen, and silica. Operation below these parameter limits helps to control electrolytes. In total, these controls have been shown by operating experience to have been effective in minimizing each form of electrochemical corrosion, including galvanic corrosion, pitting corrosion, crevice corrosion, general corrosion, and SCC. Flow blockage due to fouling is managed by controlling the creation of corrosion products.

During the audit, the staff asked the applicant to explain how the Water Chemistry Program manages flow blockage due to fouling in certain components. The applicant stated that flow blockage is managed by minimizing the creation of corrosion products. The Water Chemistry Program has been credited for managing flow blockage due to fouling for the core spray nozzles (in combination with the Reactor Vessel and Internals Structural Integrity Program) and the control rod drive (CRD) hydraulic control unit filters (in combination with the One-Time Inspection Program). The basis for crediting the Water Chemistry Program is that this program monitors and controls parameters such as level of contaminants, conductivity, and pH. Control of these parameters serves to inhibit the formation of corrosion products. These corrosion products, in the form of rust, scale, or particles, have the potential to foul filters and spray nozzles; therefore, preventing the formation of corrosion products is an effective means to manage this potential aging effect. The applicant stated that previous inspections of these components have shown that the Water Chemistry Program is effective in managing this aging effect.

The staff reviewed and determined that the applicant’s response is acceptable on the basis that controlling the buildup of corrosion products decreases the potential for fouling of nozzles and filters, and past inspections of these components have indicated no fouling problems. Therefore, the staff concluded that this exception is acceptable.

Exception 3 - Parameters Monitored/Inspected. The GALL Report identifies the following recommendations for the “parameters monitored/inspected” program element associated with the exception taken:

> The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemistry integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.
>
> BWR Water Chemistry: The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommends that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

Exception: The Water Chemistry Program does not require the monitoring of hydrogen peroxide, which is included in the description section of GALL AMP XI.M2.

During the audit, the staff asked the applicant to explain the impact of not monitoring hydrogen peroxide on the effectiveness of program, and how the electrochemical potential of the water will be determined. In response, the applicant stated that reliable hydrogen peroxide data are exceptionally difficult to obtain. Decomposition of hydrogen peroxide to water and oxygen in reactor coolant sample lines is very rapid and BSEP has no data with regard to locations where radiation is sufficient to generate additional hydrogen peroxide resulting in significant steady state concentrations.

The applicant further stated that electrochemical potential (ECP) values can be calculated using verified computer models, such as the BWRVIP radiolysis/ECP model, and can be directly correlated with measurements of other plant parameters (oxygen, main steam line radiation levels, etc.). Computer simulation of water radiolysis can describe concentrations of hydrogen peroxide in the various parts of the BWR primary circuit and in the main steam. The BWRVIP radiolysis/ECP model has proven to be effective in determining plant water chemistry conditions. The model has been evaluated and developed over a decade. Model simulations have been performed for BWRs and are in excellent agreement with reliable chemistry measurements obtained from steam and recirculation piping. The model contains predictive models for radiolysis, and ECP is the measure of the oxidizing environment. The output is region-by-region predictions for the concentration of oxidizing species in the coolant and the ECP. BSEP uses a radiolysis model to estimate the hydrogen peroxide. BWRVIP-79, Section 5.2.1.13, allows such use of models to estimate hydrogen peroxide and hence the determination of the ECP.

Although hydrogen peroxide is not monitored, the ECP is calculated using the predictive radiolysis models and can be used to determine concentrations of hydrogen peroxide in the water. Therefore, the staff concluded that this exception is acceptable.

Exception 4 - Monitoring and Trending. The GALL Report identifies the following recommendations for the "monitoring and trending" program element associated with the exception taken:

> The frequency of sampling water chemistry varies (e.g., continuous, daily, weekly, or as needed) based on plant operating conditions and the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions.

Exception: The latest version of the BWR Water Chemistry Guidelines may specify slightly different sampling frequencies than those specified in BWRVIP-29.

The staff found EPRI TR-103515-R2 acceptable because the program is based on updated industry experience. The applicant stated that BSEP and industry-wide operating experience confirms the effectiveness of the Water Chemistry Program.

The applicant's response for Exception 1, above, also pertains to this exception. The staff determined that this exception is acceptable since the applicant has been following the recommendations given in the EPRI-recommended HWC program, which is an enhancement to the Water Chemistry Program recommended by the GALL Report.

Operating Experience. In the LRA, the applicant stated that the EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use in the industry. The specific examples of BWR industry operating experience are as follows: (1) IGSCC has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel-based alloys; (2) significant cracking has occurred in piping welds of recirculation, core spray, residual heat removal, and reactor water cleanup systems; (3) IGSCC has also occurred in a number of vessel internal components, including the core shroud, access hole cover, top guide, and core spray spargers; and (4) no occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported.

The applicant also stated that the operating experience at BSEP is similar to that of the industry. Cracking due to IGSCC was found in reactor recirculation, reactor water cleanup, and jet pump instrumentation system piping; however, under the BWR Stress Corrosion Cracking Program, appropriate preventive measures were implemented to mitigate IGSCC in these systems.

The applicant’s operating experience review in the LRA bases document for the Water Chemistry Program states that this program is continually upgraded based on industry experience and research. These continuous improvements are to assure the capability of the Water Chemistry Program to support the safe operation of BSEP throughout the extended period of operation. Also, after implementing HWC in the late 1980s, and zinc injection in mid-1990s, the applicant has observed no such degradation in these systems.

On the basis of its review of the above industry and plant-specific operating experience and on discussions with the applicant's technical staff, the staff concluded that the applicant’s Water Chemistry Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.2, the applicant provided the UFSAR supplement for the Water Chemistry Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s Water Chemistry Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 Flow-Accelerated Corrosion Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.5, “Flow-Accelerated Corrosion Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with exception and enhancement, with GALL AMP XI.M17, “Flow-Accelerated Corrosion."

In the LRA, the applicant stated that this program provides for prediction, inspection, and monitoring of piping and fittings for a loss of material aging effect due to FAC so that timely and appropriate action may be taken to minimize the probability of experiencing a flow-accelerated corrosion (FAC)-induced consequential leak or rupture. The FAC Program elements are based on the recommendations identified in NSAC-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” which requires controls to assure the structural integrity of carbon steel lines containing high-energy fluids (two phase as well as single phase). The FAC Program manages loss of material in carbon steel piping and fittings.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and enhancement and the associated justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provides an assessment of the AMP’s consistency with GALL AMP XI.M17.

In the LRA, the applicant stated the following exception and enhancement to the program elements listed for GALL AMP XI.M17.

Exception - Scope of Program. The GALL Report identifies the following recommendation for the “scope of program” program element associated with the exception taken:

> The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. . . . The NSAC-202L-R2 (April 1999) provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes.

Exception: NSAC-202L-R2 advises that portions of systems and water-containing components greater than 200 EF can be excluded from further FAC susceptibility evaluation if they contain superheated steam with no moisture content. The FAC susceptibility analyses allow for the exclusion of components operating with superheat or with a steam quality exceeding 99.5 percent from further susceptibility evaluation. Typical BWR steam qualities are in excess of 99.5 percent, but some moisture is present.

FAC susceptibility analyses predate issuance of NSAC-2002L-R2. Experience with FAC modeling has shown that piping with high steam quality (>99.5 percent) yields very low predicted wear rates (<1.5 mils/year) and very high estimated remaining life projections. This exception reduces the amount of steam system piping modeled explicitly with CHECWORKS, but does not alter the primary inspection focus in accordance with NSAC-202L-R2.

As discussed in the staff's Audit and Review Report, the applicant provides general directions for implementing the EPRI guidelines in NSAC-202L-R2, including conducting an analysis to determine critical locations, performing limited baseline inspections to determine the extent of thinning at these locations, and performing follow-up inspections to confirm the predictions, or repairing components as necessary. The EPRI guidelines in NSAC-202L-R2 state that portions of systems with water-containing components greater than 200EF can be excluded from further FAC susceptibility evaluation if they contain superheated steam with no moisture content. BSEP cautions analysts not to use the results of a CHECWORKS ranking analysis as absolute values. The component predictive results can be used to establish a component's susceptibility relative to another component, but should not be used on a quantitative basis to determine a specific wear rate or specific service life.

The staff determined that the piping eliminated from the CHECWORKS model would remain in the FAC Program and could be selected for inspection as part of the FAC Program implementation Plan. The staff determined that excluding piping, which may contain moisture, from the CHECWORKS model is standard industry practice. Therefore, the staff concluded that this exception is acceptable on the basis that it will not degrade the information provided by CHECWORKS and the piping being eliminated would have high estimated remaining life projections.

On the basis of its review of the above exception, and on discussions with the applicant's technical staff, the staff concluded that the exception stated by the applicant for the Flow-Accelerated Corrosion Program to the program elements for GALL AMP XI.M17 are acceptable.

Enhancement - Scope of Program. The GALL Report identifies the following guidance for the "scope of program" program element associated with the enhancement.

> The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program.

Enhancement: Update the FAC susceptibility analyses to include additional components potentially susceptible to FAC.

In the FAC Program implementation plan, the applicant described the process for identifying components, potentially susceptible to FAC, that were removed from the FAC inspection program on the basis of susceptibility analyses. Prior to the period of extended operation, the applicant will use the systems elimination calculation to identify these additional components (see Commitment Item #2).

The staff reviewed the enhancement and determined that extending FAC Program inspections to components with lower FAC susceptibility will provide additional assurance that aging effects are identified prior to component failures.

On the basis of its review of the program elements, and on discussions with the applicant's technical staff, the staff concluded that those program elements in the FAC Program for which the applicant claims consistency with GALL AMP XI.M17 are consistent with the GALL Report.

Operating Experience. In the LRA, the applicant stated that wall-thinning problems in single-phase systems have occurred throughout the industry in feedwater and condensate systems, and in two-phase piping in extraction steam lines and moisture separator reheater and feedwater heater drains. The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam drain lines have experienced wall thinning due to FAC. The FAC Program was originally outlined in NUREG-1344 and implemented through GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning." The program has evolved through industry experience and is now described in NSAC-202L-R2. Application of the FAC Program has resulted in replacement of piping identified as being subject to FAC before experiencing a consequential leak or rupture. The FAC Program has provided an effective means of ensuring the structural integrity of high-energy carbon steel systems.

The applicant stated that the current FAC Program is an outgrowth of the applicant's response to GL 89-08, "Errosion/Corrosion-Induced Pipe Wall Thinning." Since its inception, this program has evolved based on industry best practices, self-assessment, and NRC inspections. The applicant had previously observed significant, but localized, erosion on the internal surfaces of several carbon steel valve bodies which was resolved through the applicant's Corrective Action Program. The affected safety-related (SR) valves were the 24-inch residual heat removal/low pressure coolant injection (RHR/LPCI) system injection and 16-inch suppression pool isolation valves as described in Information Notice (IN) 89-01, "Valve Body Erosion." This erosion was attributed to throttling the valves too far in the closed position, but not to FAC.

On the basis of its audit, the staff determined that from 1994 to 1996 three corrective action reports identified multiple through-wall failures. From 1996 to present, three corrective action reports identified multiple wall degradations that required repair or replacement. In 1994, a single through-wall leak was identified in a component that is in the FAC Program. The staff determined that the FAC Program has been effective in reducing the number of through-wall leaks.

UFSAR Supplement. In LRA Section A.1.1.5, the applicant provided the UFSAR supplement for the FAC Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's FAC Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exception and the associated justifications, and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report

AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Bolting Integrity Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.6, “Bolting Integrity Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions and enhancement, with GALL AMP XI.M18, “Bolting Integrity.”

In the LRA, the applicant stated that this program addresses aging management requirements for bolting on mechanical components within the scope of license renewal. The Bolting Integrity Program utilizes industry recommendations and EPRI guidance which considers material properties, joint/gasket design, chemical control, service requirements, and industry/site operating experience in specifying torque and closure requirements. The program relies on recommendations for a Bolting Integrity Program, as delineated in NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” and industry recommendations, as delineated in EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” and TR-104213, “Bolted Joint Maintenance & Application Guide,” for pressure-retaining bolting within the scope of license renewal. While the AMP discussion reconciles structural bolting issues presented in the GALL Report for the sake of completeness, this AMP does not prescribe aging management of structural bolting.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and enhancement and the associated justifications to determine whether the AMP, with the exceptions and enhancement, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provides an assessment of the AMP’s consistency with GALL AMP XI.M18.

Exception 1 - Scope of Program. The GALL Report identifies the following recommendation for the “scope of program” program element associated with the exception taken.

> The program covers all bolting within the scope of license renewal including safety-related bolting, bolting for NSSS component supports, bolting for other pressure retaining components, and structural bolting. The program covers both greater than and smaller than 2-in. diameter bolting. The Nuclear Regulatory Commission (NRC) staff recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339. The industry’s technical basis for the program for safety related bolting and guidelines for material selection and testing, bolting preload control, inservice inspection (ISI), plant operation and maintenance, and evaluation of the structural integrity of bolted joints, are outlined

> in EPRI NP-5769, with the exceptions noted in NUREG 1339. For other bolting, this information is set forth in EPRI TR-104213.

Exception: The Bolting Integrity Program is not utilized to address aging management requirements for structural bolting. Structural bolting is discussed herein only in response to specific issues raised by the GALL Report in its Bolting Integrity Program description. Implementation of aging management requirements for structural bolting is accomplished under the ASME Section XI, Subsection IWF Program and the Structures Monitoring Program.

Exception 2 - Parameters Monitored/Inspected. The GALL Report identifies the following recommendation for the "parameters monitored/inspected" program element associated with the exception taken.

> The aging management program (AMP) monitors the effects of aging on the intended function of closure bolting, including loss of material, cracking, and loss of preload. High strength bolts (actual yield strength $\geq$ 150 ksi) used in NSSS component supports are monitored for cracking. Bolting for pressure retaining components is inspected for signs of leakage. Structural bolting is inspected for indication of potential problems including loss of coating integrity and obvious signs of corrosion, rust, etc.

Exception: The Bolting Integrity Program is not utilized to prescribe monitoring and trending for bolting within the ASME Section XI boundaries. These activities are addressed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The Bolting Integrity Program is not utilized to address aging management requirements for structural bolting. Structural bolting is discussed herein only in response to specific issues raised by the GALL Report in its Bolting Integrity Program description. Implementation of aging management requirements for structural bolting is accomplished under the ASME Section XI, Subsection IWF Program and the Structures Monitoring Program.

Exception 3 - Detection of Aging Effects. The GALL Report identifies the following recommendation for the "detection of aging effects" program element associated with the exception taken.

> Inspection requirements are in accordance with the American Society of Mechanical Engineers (ASME) Section XI, Table IWB 2500-1 or IWC 2500-1 (1995 edition through the 1996 addenda) and the recommendations of EPRI NP-5769. For Class 1 components, Table IWB 2500-1, examination category B-G-1, for bolting greater than 2 in. in diameter, specifies volumetric examination of studs and bolts and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. All high strength bolting used in nuclear steam supply system (NSSS) component supports are to be inspected also to the requirements for Class 1 components, examination category B-G-1. Examination category B-G-2, for bolting 2 in. or smaller requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, examination category B-D, for bolting greater than 2 in. in diameter, requires volumetric examination of studs and bolts. Examination categories B-P or C-H require visual examination (IWA-5240) during system leakage testing of all pressure-retaining Class 1 and 2 components, according to Tables IWB 2500-1 and IWC 2500-1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in

> leakage. The extent and schedule of inspections, in accordance with IWB 2500-1 or IWC 2500-1, assure detection of aging degradation before the loss of the intended function of the closure bolting. Structural bolting both inside and outside containment is inspected by visual inspection. Degradation of this bolting may be detected and measured either by removing the bolt, proof test by tension or torquing, by in situ ultrasonic tests, or hammer test. If this bolting is found corroded, a closer inspection is performed to assess extent of corrosion.

Exception: The Bolting Integrity Program is not utilized to prescribe acceptance criteria for bolting within Section XI boundaries. These activities are addressed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The Bolting Integrity Program is not utilized to address aging management requirements for structural bolting, including nuclear steam supply system supports. Structural bolting is discussed herein only in response to specific issues raised by the GALL Report in its Bolting Integrity Program description. Implementation of aging management requirements for structural bolting is accomplished under the ASME Section XI, Subsection IWF Program and the Structures Monitoring Program.

Exception 4 - Monitoring and Trending. The GALL Report identifies the following recommendation for the “monitoring and trending” program element associated with the exception taken.

> The inspection schedules of ASME Section XI are effective and ensure timely detection of cracks and leakage. If bolting for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to weekly or biweekly.

Exception: Inspections of Section XI bolting is performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and not addressed in the Bolting Integrity Program. The Bolting Integrity Program does not specify leakage monitoring requirements for components outside Section XI boundaries.

The staff reviewed the above exceptions and considered them to represent a major inconsistency between the Bolting Integrity Program and GALL AMP XI.M18. During the audit, the staff requested that the applicant clarify the program to address monitoring and trending for bolting outside ASME Section XI boundaries, and the specific activities included in the scope of this AMP. In response, the applicant stated that there is considerable overlap between activities described in GALL AMP XI.M18 for the Bolting Integrity Program and those of the GALL AMP XI.M1, “ASME Section XI, Subsections IWB, IWC, and IWD Program,” and the GALL AMP XI.S3, “ASME Section XI, Subsection IWF Program.” Other activities described in GALL AMP XI.M18 are addressed in BSEP plant-specific programs for systems monitoring and structures monitoring.

Monitoring and trending for bolting inside Section XI boundaries is monitored by the ASME Section XI, Subsections IWB, IWC and IWD Program (pressure boundary bolting) and the ASME Section XI Subsection IWF Program (structural bolting), as applicable. Similarly, monitoring and trending for bolting outside Section XI boundaries is addressed by the Systems Monitoring Program or Structures Monitoring Program. The BSEP approach is to credit the Bolting Integrity Program for activities specific to bolting (torquing methodology, chemical requirements for thread lubricants/sealants, etc.) and address activities already encompassed in other AMPs within those programs. Information and bases regarding specific activities crediting other AMP's is provided in the discussion of program elements in BSEP procedures as discussed in the Audit and Review Report.

The staff reviewed BSEP documentation, as discussed in the staff's Audit and Review Report, and determined that it provides information and bases regarding specific activities crediting other AMPs. Based on a review of the applicant's response, the staff determined that the applicant appropriately manages aging of structural bolting, including bolting for NSSS component supports, by implementing the ASME Section XI, Subsection IWF Program and Structures Monitoring Program. Pressure-retaining bolting within the boundaries of the ASME Section XI is also appropriately managed by this AMP, in combination with the ASME Section XI, Subsections IWB, IWC, and IWD Program, and Systems Monitoring Program.

With regard to the applicant's exception to the program element for monitoring and trending, the staff asked the applicant to clarify the activities it uses to monitor leakage for pressure-retaining bolting outside the ASME Section XI boundaries. In its response, the applicant stated that the plant procedure used to implement the Systems Monitoring Program is based on guidance in EPRI Technical Report TR-107668, "Guideline for System Monitoring by System Engineers." This procedure requires that inspections be performed on a frequency sufficient to identify age-related degradation prior to loss of function, and includes criteria for inspections of bolted connections and for system leakage. Deficiencies noted are subject to the Corrective Action Program, which ensures that the deficiency is addressed based on its implications on plant safety, reliability, and quality.

The staff reviewed the applicant's response and requested information on the leakage inspection frequency used and how it compares to the recommendations in the GALL Report. The applicant stated that EPRI Report TR-107688 does not recommend a set frequency for leakage inspections. Instead, monitoring is based on consideration of a range of criteria, including criticality of the system/component, consequences of failure, operating experience, etc. Comparison of the EPRI recommendations with the recommendations in the GALL Report shows consistency since the GALL Report also does not specify a fixed frequency for leakage inspections.

Additionally, as part of its audit of the AMRs for the ESF systems in LRA Section 3.2, the staff asked for clarification on the Bolting Integrity Program as it relates to pressure-retaining bolting. The applicant committed to revising the Bolting Integrity Program to include the ASME inservice inspection requirements, along with monitoring and trending activities for pressure-retaining bolting outside the boundaries of ASME Section XI (see Commitment Item #3). This commitment will obviate the need for several of the exceptions stated above for this program.

Based on the applicant's response, the staff concluded that the applicant appropriately manages the pressure-retaining bolting outside the ASME Section XI boundaries by this AMP in combination with the Systems Monitoring Program. These programs provide reasonable assurance that this class of bolting in systems outside the ASME Section XI boundaries will maintain the pressure boundary function.

On the basis of its review of the above exceptions, the applicant's responses to audit questions, and discussions with the applicant's technical staff, the staff concluded that the exceptions stated by the applicant for the Bolting Integrity Program to the program elements for AMP GALL XI.M18 are acceptable.

Enhancement - Preventive Actions. The GALL Report recommends the following criterion for the "preventive actions" program element associated with the enhancement:

> Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769 and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of safety-related bolting (see item 10, below). (NUREG-1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them.) Initial ISI of bolting for pressure retaining components includes a check of the bolt torque and uniformity of the gasket compression after assembly. It is noted that hot torquing of bolting is a leak preventive measure once the joint is brought to operating temperature and before or after it is pressurized. Hot torquing thus reestablishes preload before leak starts, but is ineffective in sealing a leak once it has begun.

Enhancement. A precautionary note will be added to plant bolting guidelines to limit the sulfur content of compounds used on bolted connections.

The staff reviewed this enhancement and determined that it is acceptable on the basis that it will provide additional assurance that improper lubricants and sealants are not used.

On the basis of its review of the above enhancement, the staff concluded that the exceptions and enhancement stated by the applicant for the Bolting Integrity Program to the program elements for GALL AMP XI.M18 are acceptable.

Operating Experience. In the LRA, the applicant stated that this program is based on industry guidance that considers operating experience. BSEP operating experience includes verification of fastener material properties in accordance with NRC Bulletin 87-02, "Fastener Testing to Determine Conformance With Applicable Material Specifications," issued on November 6, 1987, including sample-based testing, which verified that A193, B7 bolting material specifications were not only within manufacturer's specifications, but also well below the 150 ksi threshold associated with cracking.

The applicant also stated that the operating experience review shows that its Bolting Integrity Program is continually upgraded based on industry experience, research, and routine program performance. The program, through its continual improvement, assures the capability of mechanical bolting to support the safe operation of BSEP throughout the extended period of operation.

UFSAR Supplement. In LRA Section A.1.1.6, the applicant provided the UFSAR supplement for the Bolting Integrity Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Bolting Integrity Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 Open-Cycle Cooling Water System Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.7, “Open-Cycle Cooling Water System Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.M20, “Open-Cycle Cooling Water System.”

In the LRA, the applicant stated that this program relies on implementation of the recommendations of GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” to ensure that the effects of aging on the Open-Cycle Cooling Water (OCCW) (or service water) System Program will be managed for the extended period of operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW System Program.

The OCCW System Program addresses portions of the service water (SW) systems of Units 1 and 2. The program scope includes SR portions of both the nuclear and conventional SW headers. The OCCW portion of the RHR service water, diesel generator heat exchangers and associated SW piping/components, and other SR heat loads cooled by the SW system are also included within the scope of license renewal. Additionally, the program is credited with aging management of limited nonsafety-related (NSR) piping and components included within the scope of license renewal. Specifically, this includes the SW discharge header, and piping/components associated with cooling water to and from the reactor building closed cooling water (RBCCW) heat exchangers.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancements and the associated justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provide an assessment of the AMP’s consistency with GALL AMP XI.M20.

The applicant stated that to ensure that the effects of aging on the OCCW system will be managed for the extended period of operation, the program relies on implementation of the recommendations of the NRC GL 89-13, “Service Water System Problems Affecting

Safety-Related Equipment.” At BSEP, requirements and implementing documents associated with various elements of Generic Letter 89-13 are contained in Engineering Procedure 0ENP-2704, “Administrative Control of NRC Generic Letter 89-13 Requirements.”

The staff reviewed those portions of the OCCW System Program, which the applicant claims is consistent with GALL AMP XI.M20, and found that they are consistent with the GALL AMP. Furthermore, the staff concluded that the applicant’s AMP provides reasonable assurance that the program will adequately manage plant aging. The staff found the applicant’s OCCW System Program acceptable because it conforms to the recommended GALL AMP.

In the LRA, the applicant stated the following enhancements to the OCCW System Program for consistency with the recommendations in the GALL Report.

<u>Enhancement 1 - Scope of Program</u>. The GALL Report identifies the following guidance for the “scope of program” program element associated with the enhancement:

> Because the characteristics of the service water system may be specific to each facility, the OCCW system is defined as a system or systems that transfer heat from safety related systems, structures, and components (SSC) to the ultimate heat sink (UHS). If an intermediate system is used between the safety-related SSCs and the system rejecting heat to the UHS, that intermediate system performs the function of a service water system and is thus included in the scope of recommendations of NRC GL 89-13.

<u>Enhancement</u>: The scope of the OCCW System Program will include portions of the SW system credited in the AMR, including RBCCW piping, discharge piping to the weir, and piping to and from diesel generators (including expansion joints).

To ensure that the effects of aging on the OCCW system will be managed for the extended period of operation, the program relies on implementation of the recommendations of the NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” Although the OCCW System Program was originally developed in response to GL 89-13, the scope of the GALL AMP is broader than the applicant’s current licensing commitments to GL 89-13. For example, the GL 89-13 program extends to the SR boundary on the discharge piping exiting the reactor building; whereas, the scope of the OCCW System Program extends well past this boundary, including the balance of piping in the reactor building, as well as the discharge flow path through the turbine building to its exit at the discharge weir.

As a result, the scope of the existing OCCW System Program requires an enhancement to assure piping and components that are within the scope of license renewal under 10 CFR 54.4(a)(2) are addressed by the existing GL 89-13 program. The applicant stated that this enhancement will be integrated into an engineering procedure which governs the GL 89-13 program as discussed in the staff’s Audit and Review Report.

During the audit, the applicant stated that the expansion of inspection scope over that prescribed by GL 89-13 is generally that part of the system beyond SR boundaries and within the scope of license renewal. The major portions of the system in this category are identified in the program description, as noted above. Namely, these are the discharge flow paths outside the reactor building, RBCCW supply and return piping, and the diesel generator SW system. Note that the latter is safety related, but not specifically addressed in the GL 89-13 program.

The applicant further stated that, relative to the OCCW System Program description in LRA Appendix B not specifically including the reactor building heating, ventilating, and air conditioning (HVAC) system, the program descriptions in LRA Appendices A and B are general descriptions, not intended to be at a level of detail that would provide a comprehensive representation of all the systems affected by the program. This level of detail, provided in the LRA Section 3 tables and LRA Table 3.3.2-22, correctly represents coils in the emergency core cooling system (ECCS) pump room coolers as managed by the OCCW System Program.

The staff reviewed the applicant's response and determined that this enhancement is acceptable on the basis that it provides additional assurance that the effects of aging to piping and components will be adequately managed.

<u>Enhancement 2 - Parameters Monitored/Inspected</u>. The GALL Report identifies the following guidance for the "parameters monitored/inspected" program element associated with the enhancement:

> Cleanliness and material integrity of piping, components, heat exchangers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities.

<u>Enhancement</u>: Inspections will include locations where throttling or changes in flow direction might result in erosion of copper-nickel piping.

In BNP-LR-602, the applicant stated that its operating experience review has identified erosion of OCCW system piping/components associated with throttling. Specifically, erosion has been noted in NSR piping adjacent to the throttle valves where SW exits the reactor buildings, and at flow orifice plates on the line from the RHR SW booster pump motor coolers. Both of these locations are in NSR piping, which was outside the scope of the GL 89-13 program.

Prior to the period of extended operation, the applicant committed to enhance the program to require that inspections include locations where throttling of changes in flow direction might result in erosion of copper-nickel piping (see Commitment Item #4). The applicant will identify inspection locations before each outage based on operating experience, based on a review of system design by engineering personnel, and based on results of previous inspections. Guidance for selecting inspection locations will be integrated into program procedures on an ongoing basis.

The staff determined that this enhancement is acceptable on the basis that such changes to the applicant's program will provide additional assurance that the effects of aging will be adequately managed.

<u>Enhancement 3 - Detection of Aging Effects</u>. The GALL Report identifies the following guidance for "detection of aging effects" program element associated with the enhancement:

> Detection of aging effects should occur before there is loss of any structure and component intended function. This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects. Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

Enhancement: The following enhancements will be provided: (1) The RHR heat exchangers will be subject to eddy current testing; (2) verification of SW pump lube oil cooler flow and heat transfer effectiveness and replacement of RHR seal coolers will be incorporated into procedures; and, (3) inspection of a representative sample of SW pump casings will be performed (see Commitment Item #4).

In BNP-LR-602, the applicant stated that piping within the scope of license renewal of this AMP is regularly inspected for evidence of biofouling, silting, and corrosion. SW pumps, strainers, and heat exchangers are periodically disassembled and/or flushed, as appropriate. To achieve consistency with this GALL Report element, the applicant stated that, prior to the extended period of operation, the RHR heat exchangers will be subject to eddy current testing, a representative sampling of the SW pump casings will be inspected, and SW pump lube oil cooler flow and heat transfer effectiveness will be proceduralized in the OCCW System Program.

Based on a review of operating experience, the applicant determined that the RHR seal coolers require replacement each outage (every 2 years) to address corrosion concerns. Prior to the period of extended operation, the applicant committed to incorporate the requirements for replacement of RHR seal coolers into plant procedures (see Commitment Item #4). There are currently plant modifications planned to replace the current design with materials proven to be compatible with its service environment. Additionally, these coolers represent a low point in the system and would require inspection and cleaning every four years even if the corrosion concerns were addressed. Therefore, the procedural requirement will be to replace the coolers every two years, noting that this can be extended to four years on the basis of implementing the aforementioned plant modifications

The staff reviewed and determined that the applicant’s response is acceptable since it clarifies the intended actions related to the RHR coolers, and they are appropriate. On the basis of its review, the staff reviewed and determined that the enhancements described above provide additional assurance that the effects of aging in the OCCW system will be adequately managed and are, therefore, acceptable.

<u>Enhancement 4 - Monitoring and Trending</u>. The GALL Report identifies the following recommendations for the “monitoring and trending” program element associated with the enhancement:

> Inspection scope, method (e.g., visual or nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under

NRC GL 89-13. Testing and inspections are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of [microbiologically influenced corrosion] MIC, if applicable. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.

Enhancement: The RHR heat exchanger eddy current test results will be compared to previous baseline testing to determine material condition and need for ongoing monitoring.

In the LRA, the applicant stated that inspection scope, method (e.g., visual or NDE), and testing frequencies are in accordance with the utility commitments under GL 89-13. Inspections and testing are performed to manage biofouling, the condition of the surface coating, and localized pitting, and will identify the presence of MIC, if applicable. Heat exchanger performance is verified by regular inspections and cleaning. The applicant committed to compare RHR heat exchanger eddy current test results with previous test results to establish material condition and ascertain ongoing monitoring requirements (see Commitment Item #4).

The staff noted that the LRA credits the performance of regular inspections and cleaning in lieu of the recommendation in the GALL Report to document test results of the heat transfer capability of heat exchangers. Although the LRA credits regular inspections and cleaning in lieu of testing, the staff noted that the program implementing procedure specifies that testing of the capabilities of the RHR and emergency diesel generator jacket water heat exchangers would be performed and documented. The staff asked the applicant to clarify the apparent inconsistency between the implementing procedure and the OCCW System Program, as described in its LRA.

As documented in the staff's Audit and Review Report, the applicant stated that the OCCW System Program will be revised to include performance testing of the RHR and emergency diesel generator jacket water heat exchangers prior to the period of extended operation. The results from these testing activities will then be evaluated and used to prescribe testing/inspection requirements needed to ensure system functionality during the period of extended operation.

On the basis of its review of the program elements, and on discussions with the applicant's technical staff, the staff concluded that those program elements in OCCW System Program for which the applicant claims consistency with GALL AMP XI.M20 are consistent, with enhancements, with the GALL Report and, therefore, acceptable.

<u>Operating Experience</u>. In the LRA, the applicant stated that a review of recent system operating history shows that the OCCW System Program has been effective in identifying and mitigating leaks, as well as preventing equipment failures related to fouling and flow blockage. In addition, the applicant stated that a review of plant and industry operating experience has identified localized erosion of system components in throttling applications, corrosion, and silting of RHR seal coolers, and corrosion and fouling of RHR pump strainers, as items of concern. Requirements for addressing these issues are formalized in the OCCW System Program.

During the audit, the applicant stated that inspection locations will be identified each outage based on operating experience, review of system design by engineering personnel, and results of previous inspections. Guidance for selecting inspection locations will be integrated into program procedures on an ongoing basis. In addition, BSEP Procedure 0ENP-2704 is the program procedure for the GL 89-13 program. This requirement and other elements of the license renewal OCCW System Program will be integrated into that program document.

The applicant also stated that, regarding the adequacy of the current program, the license renewal OCCW System Program and the GL 89-13 program are related, but different, programs. The GL 89-13 program pertains to a defined and auditable scope based on BSEP's current licensing commitments to GL 89-13. The license renewal OCCW System Program is based on a GALL Report program description, which relies on GL 89-13, but has a broader scope that includes NSR components meeting the requirements of 10 CFR 54.4(a)(2). For example, the GL 89-13 program extends to the SR boundary on the discharge piping exiting the reactor building. The OCCW System Program scope extends well past this boundary, including the balance of piping in the reactor building as well as the discharge flow path through the turbine building to its exit at the discharge weir. The enhancements described in the LRA pertain to the license renewal OCCW System Program, not necessarily to the GL 89-13 program.

The applicant also stated that enhancements to the license renewal OCCW System Program either involve components that are outside the GL 89-13 program or are activities that already are being done and are being formalized in a program document to meet specific implementation/documentation requirements prescribed by the OCCW System Program. While consideration may be given to including these items in the GL 89-13 program, the current program is not deficient. Where deficiencies are identified, site and corporate processes include an ongoing Corrective Action Program and continuous quality improvement. Relative to operating experience with erosion, the applicant noted errosion in piping downstream of the throttle valves where SW exits the reactor buildings, and at flow orifice plates on the line from the RHR SW booster pump motor coolers. Both these locations are in NSR piping outside the scope of the current GL 89-13 program. Inspection requirements for both locations will be formalized in the integrated program document to satisfy license renewal requirements.

The applicant's response is acceptable since it presents a reasonable approach for locating erosion due to throttling, and demonstrates that past operating experience has adequately detected such erosion.

Also, the applicant stated that plant-specific operating experience has been captured by a review of the action tracking database and the Maintenance Rule (MR) database.

Selected implementing procedures were selected for review by the staff as discussed in the staff's Audit and Review Report. These stipulate that relevant site and industry Operating experience be considered in the determination of anticipated aging effects and the effectiveness of required programs.

In addition to the above reviews, equipment within the OCCW System Program are subject to ongoing reviews and assessments. The process for identifying, documenting, tracking, investigating, correcting, and trending conditions adverse to quality is described in the Corrective Action Program procedure. During the period of November 3 to November 7, 2003 and November 17 to November 21, 2003, the adequacy of this program was reviewed by a team of NRC inspectors. As documented in its report (NRC Inspection Reports: IR 05000325/2003-009 and 05000324/2003-009), the applicant's process for identifying problems and entering them into the Corrective Action Program was effective. In addition, the applicant properly prioritized issues, performed technically accurate evaluations, and developed and implemented corrective actions that were appropriate for the safety-significance of the issue.

UFSAR Supplement. In LRA Section A.1.1.7, the applicant provided the UFSAR supplement for the OCCW System Program, which states that the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms, are addressed by programs that include monitoring, inspecting, and testing to verify heat transfer, and provide assurance that aging effects for the open-cycle cooling water systems can be managed for an extended period of operation.

Prior to the period of extended operation, the program will be enhanced to ensure that (1) the program scope includes portions of the SW system credited in the AMR, including NSR piping; (2) the RHR heat exchangers will be subject to eddy current testing with results compared to previous testing to evaluate degradation and aging; (3) a representative sampling of SW pump casings will be inspected; (4) program procedures will be enhanced to include verification of cooling flow and heat transfer effectiveness of SW pump oil cooling coils, inspections associated with SW flow to the DGs (including inspection of expansion joints), and inspection and replacement criteria for RHR seal coolers; and, (5) piping inspections will include locations where throttling or changes in flow direction might result in erosion of copper-nickel piping.

Following incorporation of this enhancement, the OCCW System Program will be consistent with the corresponding program described in the GALL Report.

As documented in the staff's Audit and Review Report, by letter dated March 14, 2005, the applicant committed to revise the OCCW System Program to include performance testing of the RHR and emergency diesel generator jacket water heat exchangers prior to the period of extended operation (see Commitment Item #4). The results from these testing activities will then be evaluated and used to prescribe testing and inspection requirements needed to ensure system functionality during the period of extended operation.

The staff reviewed this section and determined that, with the addition of the applicant's commitment to complete performance testing of the RHR and emergency diesel generator (EDG) jacket water heat exchangers, the USAR supplement provides an adequate summary description as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's OCCW System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 Closed-Cycle Cooling Water (CCCW) System Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.8, "Closed-Cycle Cooling Water System Program." In the LRA, the applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.M21, "Closed-Cycle Cooling Water System."

In the LRA, the applicant stated that this program addresses aging management of components in the RBCCW and DG jacket water cooling systems. These systems are closed cooling loops with controlled chemistry, consistent with the GALL Report description of a CCCW system. The program relies on maintenance of system corrosion inhibitor concentrations within specified limits of EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," to minimize corrosion. Surveillance testing and inspection in accordance with standards in EPRI TR-107396 for CCCW systems is performed to evaluate system and component performance. These measures will ensure that the CCCW system and components serviced by the CCCW system are performing their functions acceptably.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancements and the associated justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP's consistency with GALL AMP XI.M21.

In addition, the staff reviewed a selected sample of BSEP implementing procedures, as documented in the staff's Audit and Review Report, which incorporate the guidelines of EPRI TR-107396 and provide chemistry control parameters and corrective actions to be performed if a specific parameter is exceeded.

In the LRA, the applicant stated that the CCCW System Program addresses aging management of components in the RBCCW and DG jacket water cooling systems. The RBCCW and EDG jacket water cooling systems are closed cooling loops with controlled chemistry, consistent with the description of a CCCW system in the GALL Report. These systems use demineralized water and a chemical corrosion inhibitor.

In the LRA, the applicant stated the enhancements to the program elements to be consistent with the recommendations in the GALL Report.

Enhancement 1 - Parameter Monitored/Inspected - The GALL Report identifies the following guidance for the "parameter monitored/inspected" program element associated with the enhancement:

> The aging management program (AMP) monitors the effects of corrosion by surveillance testing and inspection in accordance with standards in EPRI TR-107396 to evaluate system and component performance. For pumps, the parameters monitored include flow and discharge and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure.

Enhancement: External inspections will be performed on cooling fins and surfaces of the DG combustion air intercoolers for corrosion or fouling.

In the LRA, the applicant stated that testing and inspections of the DG jacket water cooling water heat exchangers are performed regularly, as prescribed by the OCCW System Program. The diesel generator combustion air intercoolers are regularly tested as a part of the diesel generators. Testing of the NSR RBCCW system heat exchangers is not required on a prescribed basis. However, since this system is in the scope of license renewal only for spatial interaction considerations, heat transfer is not critical to support its license renewal intended function.

The DG is subjected to an array of preventive maintenance (PM) activities that include disassembly and inspection of heat exchangers, and other critical components exposed to the DG jacket water cooling water. The applicant commits to enhancing current PM activities to include external inspections of cooling fins and surfaces of the DG combustion air intercoolers for corrosion or fouling (see Commitment Item #5).

The efficacy of CCCW system chemistry in preventing corrosion (including pitting and crevice corrosion) is supported by the condition of system components upon disassembly and the lack of site-specific Operating experience regarding corrosion in system components. The applicant stated that its operating experience review found no incidence of age-related degradation associated with the DG jacket water system.

During the audit, the staff determined that the above enhancement to include visual inspection of cooling fins and surfaces of the intercoolers provides assurance that the effects of aging to components that are within the scope of license renewal will be adequately managed and, therefore, is acceptable.

<u>Enhancement 2 - Detection of Aging Effects</u>. The GALL Report identifies the following guidance for the “detection of aging effects” program element associated with the enhancement:

> Control of water chemistry does not preclude corrosion at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion would result in degradation of system or component performance. The extent and schedule of inspections and testing in accordance with EPRI TR-107396, assure detection of corrosion before the loss of intended function of the component. Performance and functional testing in accordance with EPRI TR-107396, ensures acceptable functioning of the CCCW system or components serviced by the CCCW system. For systems and components in continuous operation, performance adequacy is determined by monitoring data trends for evaluation of heat transfer fouling, pump wear characteristics, and branch flow changes. Components not in operation are periodically tested to ensure operability.

Enhancement: PM activities will include inspections of DG combustion air intercoolers and heat exchangers. These activities will ensure that applicable potential aging effects are identified.

The DGs and DG jacket water cooling system are not normally in service but are closely monitored during regular testing for trends indicative of degraded performance. In the LRA, the applicant stated that the DGs are tested regularly as required by plant technical specifications.

The DG jacket water cooling system is regularly tested as part of the DG and inspected regularly under the open-cycle cooling water system and PM programs.

The DG is subjected to an array of PM activities that include disassembly and inspection of heat exchangers, and other critical components exposed to the DG jacket water cooling water. The DG combustion air intercoolers are regularly tested as a part of the DGs. In the LRA, the applicant commits to enhancing PM activities to include external inspections of combustion air intercoolers (see Commitment Item #5).

The applicant stated that the CCCW system chemistry has been effective in preventing corrosion (including pitting and crevice corrosion) and that this conclusion is supported by the condition of system components upon disassembly and the lack of site-specific operating experience regarding corrosion in system components.

The staff determined that this enhancement is acceptable on the basis that it provides assurance that the effects of aging to components that are within the scope of license renewal will be adequately managed.

On the basis of its review of the above enhancements, review of selected documents as documented in the staff's Audit and Review Report, and on discussions with the applicant's technical staff, the staff concluded that the enhancements stated by the applicant for the CCCW System Program to the program elements for GALL AMP XI.M21 are acceptable.

<u>Operating Experience</u>. Degradation of closed-cycle cooling water systems due to corrosion product buildup (NRC Licensee Event Report [LER] 93-029-00) or through-wall cracks in supply lines (NRC LER 91-019-00) has been observed in operating plants.

The applicant stated that, since the GALL Report is based on industry operating experience through April 2001, more recent industry operating experience has been reviewed for applicability. Subsequent operating experience will be captured through the normal operating experience review process.

In the LRA, the applicant stated that an operating experience review found no incidence of age-related degradation associated with the CCCW systems. RBCCW operating experience at BSEP includes SW-related (tubeside) fouling and corrosion or plugging of the RBCCW heat exchanger tubes. Since these components are within the scope of license renewal for spatial interaction only, the shell performs an intended function, and tube degradation does not impact the scope of AMRs. Moreover, aging management of raw water components is performed by the OCCW system. BSEP operating experience review found no incidence of age-related degradation associated with the DG jacket water system.

During the audit, the staff also reviewed the results of a BSEP self-assessment of the CCCW System Program. The objective of this assessment was to ensure that the BSEP chemistry unit closed cooling water activities are conducted in accordance with applicable procedures, guidelines, and regulatory compliance. The applicant performed the evaluation during the period of November 4 to 8, 2002, and included the RBCCW and the DG jacket water systems. As documented in the BSEP Report described in the staff's Audit and Review Report, an evaluation performed in May 2001 by the Institute of Nuclear Power Operations determined that the applicant was not effectively evaluating chemistry parameters to identify trends that may lead to out of specification conditions in the closed-cooling water systems. To address and correct this issue, the applicant completed Adverse Condition Investigation (AR 44704) in July 2001. The staff found that the 2002 self-assessment concluded that the CCCW System Program ensures that chemistry parameters are maintained within specifications. The applicant stated that the operating experience review of the CCCW System Program is continually upgraded based on site and industry experience and research.

UFSAR Supplement. In LRA Section A.1.1.8, the applicant provided the UFSAR supplement for the Closed-Cycle Cooling Water System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's CCCW System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 Inspection of Overhead Heavy Load and Light Load Handling Systems Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.9, "Inspection of Overhead Heavy Load and Light Load Handling Systems Program." In the LRA, the applicant stated that this is an existing program that is consistent, with enhancement(s), with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

In the LRA, the applicant stated that this program provides for the inspection of the reactor building bridge cranes, refueling platforms, and the intake structure gantry crane. The inspections monitor structural members for the absence or signs of corrosion other than minor surface corrosion and crane rails for abnormal wear. The inspections are performed annually for the reactor building bridge cranes and the intake structure gantry crane, and every fuel cycle for the refueling platforms. The diesel generator building cranes do not credit this program for aging management activities, because they are addressed as structural steel (monorails) and managed under the Structures Monitoring Program.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancements and the associated justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP's consistency with GALL AMP XI.M23.

On the basis of its audit and discussions with the applicant, the staff determined that the Inspection of Overhead Heavy Load and Light Load Handling Systems Program is implemented through procedures and work order packages. BSEP's standard procedure, as documented in the staff's BSEP Audit and Review Report, provides guidance for implementing the Inspection of Overhead Heavy Load and Light Load Handling Systems Program and describes the scope of the program. Monitoring and trending are not required as part of the Inspection of Overhead Heavy Load and Light Load Handling Systems Program. BSEP's PM procedures provide directions for condition monitoring of specific cranes and delineate the frequencies of the maintenance inspections. The frequency of inspections is consistent with industry practice.

Work packages provide directions concerning the parameters monitored or inspected, the detection of aging effects, and the associated acceptance criteria. The acceptance criterion for structural members is the absence of signs of corrosion other than minor surface corrosion. The acceptance criterion for crane rails is the absence of abnormal wear.

The applicant assessed the load cycle limits for cranes that are within the scope of license renewal using TLAAs. The applicant concluded that the analyses of the cranes have been projected to the end of the period of extended operation. The staff documented its evaluation of these TLAAs in SER Section 4.7.3.

In the LRA, the applicant stated that the following enhancements will be implemented to make this AMP consistent with the recommendations in the GALL Report.

<u>Enhancement 1 - Scope of Program</u>. The GALL Report identifies the following guidance for the "scope of program" program element associated with the enhancement.

> The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4 and the effects of wear on the rails in a rail system.

<u>*Enhancement*</u>: The applicant will revise administrative controls to include all cranes within the scope of license renewal, not only the SR cranes (see Commitment Item #6).

The applicant identified the turbine building bridge crane and the heater bay gantry crane as cranes that it plans to include in the Inspection of Overhead Heavy Load and Light Load Handling Systems Program. The applicant plans to implement procedures and/or work orders to manage the aging of these two cranes prior to the period of extended operation. On the basis of its evaluation of the applicant's existing program and planned enhancement, the staff determined that there is reasonable assurance that the enhanced program will adequately manage the aging effects for all cranes within the scope of license renewal during the period of extended operation.

<u>Enhancement 2 - Parameters Monitored/Inspected</u>. The GALL Report identifies the following guidance for the "parameters monitored/inspected" program element associated with the enhancement.

> The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes. The number and magnitude of lifts made by the crane are also reviewed.

Enhancement: The applicant will revise administrative controls to require maintenance to forward completed inspection reports to the responsible engineer (see Commitment Item #6).

During the audit, the staff determined that the enhancement to the administrative process will provide additional assurance that the responsible engineer will receive and evaluate maintenance monitoring information pertinent to the aging effects on long-lived passive components associated with cranes that are within the scope of license renewal. On the basis of its evaluation of the applicant's existing program and planned enhancement, the staff determined that there is reasonable assurance that the responsible engineers will receive completed inspection reports.

Enhancement 3 - Detection of Aging Effects. The GALL Report identifies the following guidance for the "detection of aging effects" program element associated with the enhancement.

> Crane rails and structural components are visually inspected on a routine basis for degradation. Functional tests are also performed to assure their integrity.

Enhancement: The applicant will revise administrative controls to address the following: (1) include in the program all cranes within the scope of license renewal; (2) specify an annual inspection frequency for the reactor building bridge cranes and the intake structure gantry crane, and every fuel cycle for the refuel platforms; (3) allow use of maintenance crane inspections as input for the condition monitoring of license renewal cranes; and (4) include inspection of structural component corrosion and monitoring crane rails for abnormal wear (see Commitment Item #6).

The applicant stated that it plans to revise its procedure to include all cranes within the scope of license renewal, rather than just the SR cranes; include inspecting crane rails for abnormal wear; specify an inspection frequency of every refueling cycle for the refuel platforms and an annual inspection frequency for the other cranes; and, allow the use of maintenance crane inspection results as input to the condition monitoring of license renewal cranes. The applicant also stated that its maintenance procedures, as discussed in the staff's Audit and Review Report, will be revised to include inspection of structural components for corrosion and to specifically address corrosion of structural components and cane rail wear.

During the audit, the staff determined that the enhancements provide changes to implementing procedures that will result in the inspection of Overhead Heavy Load and Light Load Handling Systems Program being consistent with the associated AMP in the GALL Report. On the basis of its evaluation of the applicant's existing program and planned enhancements, the staff determined that there is reasonable assurance that aging effects will be managed.

On the basis of its review of the above enhancements, program elements, and on discussions with the applicant's technical staff, the staff concluded that the enhancements stated by the applicant for the Inspection of Overhead Heavy Load and Light Load Handling Systems Program to the program elements for GALL AMP XI.M23 are acceptable.

Operating Experience. In the LRA, the applicant stated that based on review of plant history, BSEP has identified numerous issues involving corrosion of structural members, crane rail wear, operations, inspections, and regulatory compliance through a review of the corrective action process. Crane monitoring programs are continually being upgraded based upon industry and Progress Energy plant experience. This intrusive and proactive approach to the operation and management of cranes verifies the effectiveness of those procedures used to implement the inspection of Overhead Heavy Load and Light Load Handling Systems Program.

The applicant identified several corrective action reports associated with cranes, as documented in the staff's Audit and Review Report, which showed that adverse conditions are identified and corrected. These corrected deficiencies included: (1) underside of the intake structure crane end trucks severely corroded; (2) Unit 2 refuel bridge tracks not straight, level, or parallel with respect to each other; (3) documentation of operations inspections of refuel bridge needed to be revised to meet the daily/shift crane inspection requirements per ANSI B30.2-1976, Chapter 2-2 and NUREG-612 Section 5.1.1, AR 67768; and, (4) extreme buildup of metal shavings rest on the overhead crane tracks due to wear on tracks.

The staff reviewed the Adverse Condition Investigation Form, which concerned the finding of severe corrosion on the underside of the intake structure crane end trucks. The applicant used ultrasonic tests (UTs) to assess the structural integrity of the end trucks. The UT results indicated that the wall thickness exceeded the nominal thickness. The applicant cleaned and painted the crane end trucks. Additional inspections by the applicant verified the absence of material degradation. The staff determined that the applicant's corrective actions taken in response to identified aging degradation were effective in managing the degradation.

UFSAR Supplement. In LRA Section A.1.1.9, the applicant provided the UFSAR supplement for the Inspection of Overhead Heavy Load and Light Load Handling Systems Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Inspection of Overhead Heavy Load and Light Load Handling Systems Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Fire Protection Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.10, "Fire Protection Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exception(s), with GALL AMP XI.M26, "Fire Protection."

In the LRA, the applicant stated that this program is credited for aging management of the fire protection components (penetration seals, barrier walls, ceiling and floors, and fire doors, gaseous (Halon/CO_2) fire suppression systems, the diesel-driven fire pump fuel oil supply line, and the fire pump diesel engine heat exchanger. The applicant also states that this program is implemented through various plant procedures and is proven to adequately manage the aging effects associated with the subject components.

As stated in UFSAR Section 9.5.1, the Fire Protection Program consists of design features, equipment, personnel, and procedures that combine to provide for a multi-tiered safeguard against a fire that could impact the health and safety of the public. The objectives of the Fire Protection Program are to minimize both the probability and consequences of postulated fires. The plant's Fire Hazards Analysis (FHA) evaluates the construction, occupancy, and protection for all major areas of the plant and includes an assessment of the ability of fire protection features to safeguard the components (including power, control, and instrumentation) needed to safely shut down the plant. Plant modifications, which have the potential to impact the FHA, are reviewed as part of the design change process and the UFSAR is updated as necessary.

<u>Staff Evaluation</u>. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exceptions and the associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provides an assessment of the AMP’s consistency with GALL AMP XI.M26.

The applicant stated that the Fire Protection Program is staffed by qualified personnel with adequate resources committed to program activities and managed in accordance with plant administrative controls. The program ensures the maintenance of necessary fire prevention and mitigation features through periodic inspections and performance testing. All relevant parameters observed during scheduled testing and inspection, and during routine work activities, are recorded. Discrepancies thus identified which affect the fire protection components (penetration seals, barrier walls, ceiling and floors, and fire doors), gaseous (Halon/CO_2) fire suppression systems, and the diesel-driven fire pump fuel oil supply line, are then further evaluated and trended to allow timely and appropriate corrective action.

The applicant further stated that based on its review of operating history data and assessment results, the Fire Protection Program has provided an effective means of ensuring the preservation from fire of the safe shutdown capability of BSEP, and through its continual improvement, is assured of the capability to support the safe operation of BSEP throughout the extended period of operation.

In the LRA, the applicant stated the following exceptions to the program elements listed in the GALL Report.

<u>Exception 1 - Parameters Monitored/Inspected and Detection of Aging Effects</u> The GALL Report identifies the following specifications for the “parameters monitored/inspected” and “detection of aging effects” program elements associated with the exception taken:

> Visual inspection of penetration seals detects cracking, seal separation from walls and components, and rupture and puncture seals. Visual inspection (VT-1 or equivalent) of 10 percent of each type of penetration seal in walkdowns at least every refueling outage.

Exception: The penetration seal sample size utilized by BSEP is less than the GALL Report recommended sample size of 10 percent. However, based on plant operating history, the sample provides reasonable assurance the entire population is adequately monitored. Additionally, NRC Interim Staff Guideline (ISG)-04, as discussed in the staff's Audit and Review Report, has modified the GALL recommendation to a sample size of approximately 10 percent.

The applicant stated that a visual inspection of a statistical sample of fire barrier penetration seals every 18 months is mandated by procedure. The sample is selected based on building seal population utilizing a multiple sampling program with an acceptable quality level of 96 percent in accordance with ANSI/ASQC Z1.4-1993. Based on inspection results, the scope of inspection is expanded to include additional seals. The sample size of penetration seal inspections during each inspection interval may, depending on the number of discrepancies found, be greater or less than 10 percent. The applicant further stated that the visual inspections are conducted in accordance with established procedures and inspection criteria is sufficient to detect any indication of cracking, seal separation from walls and components, and rupture and puncture of seals. Since the sample size is not 10 percent as recommended in the GALL Report, the applicant has identified its inspection sample process as an exception to the GALL Report.

Fire barrier penetration seals are passive elements in the facility Fire Protection Program. Maintaining their functional integrity ensures that fires will be confined or adequately retarded from spreading to adjacent portions of the facility, thereby minimizing the possibility of a single fire rapidly involving several areas of the facility prior to detection and extinguishment.

The Fire Protection Program is controlled by procedure. In addition to establishing the administrative control requirements of the Fire Protection Program, the staff's review of this procedure found it to require periodic surveillance of fire protection systems and features and that these surveillances are documented in and implemented through plant procedures.

Operability, action, and surveillance requirements for fire barrier penetrations are established by procedure. As described in the procedure, a statistical sample of penetration seals in each affected building (or group of buildings) is visually inspected every 18 months. The selection sample is to be based on building seal population utilizing a multiple sampling program in accordance with ANSI/ASQC Z1.4-1993, "Sampling Procedures and Tables for Inspection by Attributes," with an acceptable quality level of 96 percent. Section 6.6.4 of this procedure further states that periodic surveillance of fire barrier penetrations using a statistical sampling method has been determined to be acceptable.

Procedures, as discussed in the staff's Audit and Review Report, are provided to ensure that the fire barrier penetration seals (fire seals) for cables, conduit, piping, ventilation ducts, fire dampers, and wall/floor fire barriers in the diesel generator building SR areas are functional. The inspection scope and frequency is expanded if an unacceptable number of seals are found to be degraded. The staff determined that these measures ensure timely detection of increased hardness and shrinkage of penetration seals before there is a loss of component intended function. No unpredicted aging unique to the BSEP materials, service conditions, or environments has been yet been identified.

During the audit, the staff asked the applicant for additional information on the technical basis for its sampling method. In its response, the applicant stated that, under its statistical sampling procedure, acceptability is based on a predetermined acceptable quality level factor of 4 which means 96 of every 100 seals are functional. This factor was used since it falls within the range judged acceptable for low safety significant systems, has been evaluated, and provides reasonable assurance that the aging of subject components will be managed. In addition, the applicant stated that a review of past surveillance results found that failures are individual, isolated problems and not the general or common mode failure of any one type of seal. Also, plant operating experience has demonstrated that penetration seal failure has not been prevalent.

The staff noted that the inspection sample size is not in strict compliance with the recommendations in the GALL Report; however, it is based on established statistical sampling methods contained in ANSI/ASQC Z1.4-1993 "Sampling Procedures and Tables for Inspection by Attributes." Also, the sample size is consistent with ISG-04, which requires a sample size of approximately 10 percent, since the applicant stated that the sampling selection methodology provides a sample size which may be greater or less than 10 percent. In addition, visual inspections are conducted in accordance with established procedures, and inspection criteria appear to be sufficient to detect any indication of cracking, seal separation from walls and components, and rupture and puncture of seals.

As evidenced by the applicant's review of operational history, the sampling techniques and surveillance procedures currently employed provide reasonable assurance that the fire barrier penetration systems will perform their intended functions during the period of extended operation.

On the basis of its review, the staff determined that the above exception is acceptable.

<u>Execption 2 - Parameters Monitored/Inspected and Detection of Aging Effects</u> The GALL Report identifies the following specifications for the "parameters monitored/inspected" and "detection of aging effects" program elements associated with the exception taken:

> Visual inspection of penetration seals detects cracking, seal separation from walls and components, and rupture and puncture seals. Visual inspection (VT-1 or equivalent) of 10% of each type of penetration seal in walkdowns at least every refueling outage.

<u>Exception</u>: The Fire Protection Program does not require visual inspection of each type of penetration seal but rather a statistical sampling of penetration seals in each affected building (or group of buildings). However, this sampling method is determined to be both acceptable for the BSEP configuration and adequate to assure the capability of the penetration seals to preserve the fire safe shutdown capability. Based on the sampling process and frequency of inspections, a representative sampling is assured.

The applicant stated that a visual inspection of a statistical sampling of fire barrier penetration seals every 18 months is mandated by procedure 0PLP-01.2, "Fire Protection System Operability, Action, and Surveillance Requirements." The sample is selected based on building seal population utilizing a multiple sampling program with an acceptable quality level of 96 percent in accordance with ANSI/ASQC Z1.4-1993. On the basis of inspection results, the scope of the inspection may be expanded to include additional seals. The applicant further stated that the visual inspections are conducted in accordance with established procedures, and inspection criteria is sufficient to detect any indication of cracking, seal separation from walls and components, and rupture and puncture of seals. Inspection acceptance criteria are provided for various penetration types and include shrinkage, cracking, gaps, and seal intact; they are structured to verify operability of the penetration seals. The subject inspection criteria are adequate to identify penetration seal degradation and are consistent with those identified by this program element.

As discussed above, the staff reviewed implementing procedures. Visual inspections are conducted in accordance with established procedures and inspection criteria appear to be sufficient to detect any indication of cracking, seal separation from walls and components, and rupture and puncture of seals. No unpredicted aging unique to the BSEP materials, service conditions, or environments have been yet been identified.

As evidenced by the operational history data, the sampling techniques and surveillance procedures currently employed provide reasonable assurance that the fire barrier penetration systems will perform their intended functions during the period of extended operation. On the basis of its review, the staff determined that the above exception is acceptable.

<u>Exception 3 - Parameters Monitored/Inspected and Detection of Aging Effects</u>. The GALL Report identifies the following guidance for the “parameters monitored/inspected” and “detection of aging effects” program elements associated with the exception taken:

> Periodic visual inspection and functional test at least once every six months examines the signs of degradation of the halon/carbon dioxide fire suppression system. The suppression agent charge pressure is monitored in the test. Inspections performed at least every month to verify that the extinguishing agent supply valves are open and the system is in automatic mode.

<u>Exception</u>: ISG-04 modified the GALL Report program element to recommend system functional testing at least once every six months for the Halon/CO_2 fire suppression system. The subject systems are verified as being properly charged every six months, but functional testing is performed less frequently. The Halon system is functionally tested annually and the CO_2 system is functionally tested every 18 months. Although these are less frequent than specified by the GALL Report, testing is sufficient to ensure the systems will perform their intended functions, as evidenced by the operational history of the systems. The BSEP gaseous suppression system functional testing procedures include the program element’s specified operability criteria. Furthermore, the specific frequency of gaseous suppression system functional testing has proven, based on operating experience, to be adequate to assure the continued capability of the systems to preserve from fire the safe shutdown capability of BSEP.

By letter dated June 17, 2002, the staff received written comments from the NEI on the fire protection system programs described in the July 2001 GALL Report. To address these comments and provide clarification of staff positions, by letter dated December 3, 2002, the staff issued ISG-04, “Aging Management of Fire Protection Systems for License Renewal.” In its cover letter the staff stated that it considers this ISG as providing clarifications, with no additional requirements, and plans to incorporate the information it contains into the improved license renewal guidance documents in a future update scheduled for late 2005. In ISG-04, the NRC staff stated that:

> The staff reviewed these items and determined that a valve lineup inspection, charging pressure inspection, and an automatic mode of operation verification are operational activities pertaining to system or component configurations or properties that may change, and are not related to aging management. Therefore, the staff position is to revise NUREG-1801 to eliminate the Halon/carbondioxide system inspections for changing pressure, valve lineups, and automatic mode of operation.

On the basis of its review and discussions with the applicant, the staff determined that the above exception is acceptable since it is consistent with guidance provided in ISG-04.

<u>Exception 4 - Detection of Aging Effects</u>. The GALL Report identifies the following recommendation for the "parameters monitored/inspected" program element associated with the exception taken:

> Periodic visual inspection and function test at least once every six months examines the signs of degradation of the halon/carbon dioxide fire suppression system.

<u>Exception</u>: General visual inspections, rather than a VT-1 or equivalent inspection, are performed for the subject components. However, the applicable inspection criteria are sufficient to assure detection of aging effects for the components.

In the LRA, the applicant stated that the Halon system is functionally tested annually, and the CO_2 system is functionally tested every 18 months. The BSEP gaseous suppression system functional testing procedures include the program element's specified operability criteria. Furthermore, the specific frequency of gaseous suppression system functional testing has proven, based on operating experience, to be adequate to assure the continued capability of the systems to preserve from fire the safe shutdown capability of BSEP.

The staff reviewed the Fire Protection System procedure which outlines the operability, action, and surveillance requirements for fire protection systems at BSEP, including the CO_2 and Halon systems, as documented in the staff's Audit and Review Report. The procedure requires that the minimum specified weight of CO_2 be verified every six months. In addition, the CO_2 system control heads, and associated ventilation dampers, are verified every 18 months to actuate manually and automatically, as appropriate, upon receipt of a simulated actuation signal. To assure no blockage, flow testing through the CO_2 flooding system headers and nozzles is performed every 18 months. With regard to the Halon system, the procedure requires verification every six months that the Halon cylinders contain at least the minimum specified liquid level and both the Halon and nitrogen supply cylinders are maintained at the minimum specified pressures. The applicant stated that both systems are functionally tested to ensure operability of manual and automatic actuation features, free flow of the suppression agents, valve and damper response.

Additionally, the applicant stated that, since Halon and CO_2 gases do not contribute to corrosion or other aging mechanisms, a six-month inspection frequency is not required to manage aging. As noted on LRA Table 3.3.2-12, no AERMs are expected for Halon and CO_2 system components exposed to these gases. The applicant further stated that in accordance with the

National Fire Protection Association (NFPA) requirements, Halon and CO_2 inspection procedures include periodic visual inspections and functional tests every 18 months to inspect for signs of degradation of the fire suppression systems. The staff determined that the applicant's response is acceptable since aging effects are not expected for the Halon and CO_2 system.

UFSAR Section 9.5.1.3.4 states that administrative controls for inspection and testing of suppression systems are provided through existing plant administrative procedures, plant operating procedures, and the quality assurance program to ensure that the Fire Protection Program and equipment are properly maintained. After installation, fire protection equipment and systems are subject to an inspection and acceptance test in accordance with the NFPA codes, Nuclear Electric Insurance Limited Members Manual, and plant procedures. After the system is in operation, periodic inspections and tests are conducted, as defined by the Fire Protection Program, Nuclear Electric Insurance Limited Members Manual, and NFPA codes.

Although the inspections and tests are less frequent than those recommended in the GALL Report, the staff determined that the current program frequency is sufficient to ensure that the systems will perform their intended functions, as evidenced by the operational history of the systems. Any degradation or mechanical damage would be observed during the test. On the basis of its review of operating experience for the Fire Protection Program, discussed below, the staff determined that this exception is acceptable.

On the basis of its review of the program elements, and on discussions with the applicant's technical staff, the staff concluded that those program elements in Fire Protection Program for which the applicant claims consistency with GALL AMP XI.M26 are consistent with the GALL Report and, therefore, acceptable.

<u>Operating Experience</u>. In the LRA, the applicant stated that the program is maintained in accordance with BSEP requirements for engineering programs. This provides assurance that the program is effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; qualified personnel are assigned as program managers, and are given authority and responsibility to implement the program; and adequate resources are committed to program activities.

The applicant also stated that the operating history and assessment results for the program show it is an effective means of ensuring the preservation from fire of the safe shutdown capability. Since these measures assure continual improvement of the program as prompted by industry experience, research, and routine program performance, the capability of the Fire Protection Program to support the safe operation of BSEP throughout the extended period of operation is, therefore, assured.

The staff's review of the BSEP procedure for its Operating Experience Program found that it directs the review of operating experience and requires operating experience to be screened and evaluated for site applicability. Operating experience sources subject to review under this procedure include Institute of Nuclear Power Operations (INPO) and World Association of Nuclear Operators (WANO) operating experience items, NRC documents (INs, GLs, Notices of Violation, and staff reports), 10 CFR Part 21 reports, and vendor bulletins, as well as corporate internal operating experience information from Progress Energy nuclear sites. Plant-specific operating experience has been captured by a review of the PassPort action tracking database and the MR database. This includes a review of work management and leak log records, applicable correspondence, and nuclear assessment records.

The applicant stated that the operating history and assessment results for the Fire Protection Program show that the Fire Protection Program it is an effective means of ensuring the preservation from fire of the safe shutdown capability of BSEP. In addition, the applicant stated that the Fire Protection Program is continually upgraded and improved as prompted by industry experience, research, and routine program performance.

BSEP operating history was specifically reviewed with respect to the industry issues presented in GALL AMP XI.M26. The results of this review are as follows: (1) IN 88-56 addresses concerns about voids, gaps, splits, etc. in silicone penetration seals. The operating history indicates no significant problems of this type; (2) IN 94-28 and IN 97-70 addresses concerns about inadequate surveillance of penetration seals. As exemplified by the lack of significant historical findings regarding this issue, surveillance requirements for the penetration seals adequately address this issue; and, (3) IN 91-47 and GL 92-08 address the inadequacy of Thermo-Lag 330-1 fire barriers for use in fire protection applications. This issue was resolved for BSEP in 2002.

On the basis of its review of the above industry and plant-specific operating experience and on discussions with the applicant's technical staff, the staff concluded that the applicant’s Fire Protection Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.10, the applicant provided the UFSAR supplement for the Fire Protection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s Fire Protection Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Fire Water Systems Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.10, “Fire Water Systems Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.M27, “Fire Water System.”

In the LRA, the applicant stated that this program includes system pressure monitoring, inspections, and periodic testing in accordance with applicable NFPA commitments. Periodic visual inspection of overall system condition and inspections of the internal surfaces of system piping, upon each entry to the system for routine or corrective maintenance, provide an effective means to determine whether corrosion and biofouling are occurring. These inspections include the sprinkler heads and assure that corrosion products that could block flow of the sprinkler heads are not accumulating. These measures will allow timely corrective action in the event of system degradation to ensure the capability of the water-based fire suppression system to perform its intended function.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancements and the associated justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provides an assessment of the AMP's consistency with GALL AMP XI.M27.

The applicant stated that periodic flow testing is performed in accordance with procedures as documented in the staff's Audit and Review Report. However, the system configuration does not support full flow testing through all affected piping and components. As an alternative, the plant maintenance process includes visual inspection of the internal surfaces of the fire protection piping upon each entry into the system for routine or corrective maintenance. The applicant further stated that these inspections include provisions for determining wall thickness to ensure against catastrophic failure and the inner diameter of the piping as it applies to the flow requirements of the fire protection system. In addition, the applicant stated that maintenance personnel are instructed to recognize degraded material conditions and equipment deficiencies, and initiate corrective action in accordance with maintenance and Corrective Action Program procedures.

In the LRA, the applicant stated the following enhancements to make this program consistent with the program in the GALL Report.

Enhancement 1 - Parameters Monitored/Inspected and Monitoring and Trending. The GALL Report identifies the following recommendation for the "parameters monitored/inspected" and "monitor and trending" program elements associated with this enhancement:

> Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. Perform periodic flow testing of the fire water system using the guidelines of NFPA 25, Chapter 13, Annexes A & D at the maximum design flow or perform wall thickness evaluations to ensure that the system maintains its intended function.
>
> Results of system performance testing are monitored and trended as specified by NFPA codes and standards. Degradation identified by internal inspection is evaluated.

Enhancement: The Fire Protection Program administrative control documents will be updated to incorporate a requirement to periodically tabulate and assess results from the initial 40-year service life tests and inspections. This information will be used to determine whether a representative sample of such results has been collected and, consequently, whether expansion of scope and subsequent test/inspection means and intervals, incorporating provisions for non-intrusive testing or other corrective action is warranted.

The staff reviewed the BSEP Fire Protection Program Manual, which identifies and describes the organizational responsibilities and authorities, core areas, key processes, process elements, supporting procedures, and interfaces which collectively form the Fire Protection Program. The manual requires that evaluations and reviews, operating requirements/limitations, surveillance requirements, and compensatory measures for fire protection features are incorporated into the Fire Protection Program Manual or supporting fire protection procedures, and plant program procedures.

On the basis of its review of the applicant's Fire Water System Program, the staff determined that this enhancement is acceptable, and that the effects of aging will be adequately managed.

Enhancement 2 - Detection of Aging Effects. The GALL Report provides the following guidance for the "detection of aging effects" program element associated with the enhancement.

> Sprinkler systems are inspected once every refueling outage to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Enhancement: The majority of the sprinkler heads have been replaced within the last ten years. The remainder (located in the diesel generator building and RHR rooms) will be replaced prior to 50 years of service. This will assure all the sprinkler heads will have less than 50 years service throughout the extended period of operation thereby obviating the need for any extended service inspections (see Commitment Item #7).

By letter dated December 3, 2002, the NRC staff issued ISG-04, "Aging Management of Fire Protection Systems for License Renewal." With regard to replacement and inspection of sprinkler heads, ISG-04 states, "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing."

In the LRA, the applicant stated that a majority of the sprinkler heads have been replaced within the last ten years. The applicant plans to install the remainder of the new sprinkler heads in Unit 1 prior to 2024 and in Unit 2 prior to 2022. This will ensure that all the sprinkler heads will have less than 50 years service throughout the extended period of operation, thereby obviating the need for any extended service inspections.

On the basis of its review, the staff determined that the above enhancement is acceptable since it is consistent with the guidance provided in ISG-04. Additionally, on the basis of its review of the program elements, and on discussion with the applicant's technical staff, the staff concluded that those program elements in BSEP AMP B.2.11 for which the applicant claims consistency with the Fire Water Systems Program in the GALL Report are consistent with the GALL Report.

Operating Experience. In the LRA, the applicant stated that the Fire Water System Program is maintained in accordance with BSEP engineering programs requirements. This provides assurance that the program is effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; qualified personnel are assigned as program managers, and are given authority and responsibility to implement the program; and adequate resources are committed to program activities.

The applicant also stated that the operating history and assessment results for the Fire Water System Program show it is an effective means of ensuring the preservation from fire of the safe shutdown capability. Since these measures assure continual improvement of the program as prompted by industry experience and research and routine program performance, the capability of the program to support the safe operation of BSEP throughout the extended period of operation is, therefore, assured.

The staff reviewed BSEP procedure for its Operating Experience Program, which directs the review of operating experience and requires that operating experience be screened and evaluated for site applicability. Operating experience sources subject to review under this procedure include INPO and WANO operating experience items, NRC documents (INs, GLs, Notices of Violation, and staff reports), 10 CFR 21 reports, and vendor bulletins, as well as corporate internal operating experience information from all Progress Energy nuclear sites. Plant-specific operating experience has been captured by a review of the PassPort action tracking database and the maintenance rule (MR) database. This included a review of work management and leak log records, applicable correspondence, and nuclear assessment records. The action tracking, MR, and operating experience databases have characteristics that make them relevant to aging concerns, and their information is suitable for keyword searches for license renewal applicability.

The applicant stated that the operating history and assessment results for the Fire Water System Program show it is an effective means of ensuring the preservation from fire of the safe shutdown capability. Since these measures support continual improvement of the program, as prompted by industry experience and research, and routine program performance, the program has the capability to support the safe operation of BSEP throughout the extended period of operation.

On the basis of its review of the above industry and plant-specific operating experience and on discussions with the applicant's technical staff, the staff concludes that the applicant’s BSEP AMP B.2.11 will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

<u>UFSAR Supplement</u>. In LRA Section A.1.1.11, the applicant provided the UFSAR supplement for the Fire Water System Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant’s Fire Water System Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff

also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Fuel Oil Chemistry Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.13, “Fuel Oil Chemisty Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M30, “Fuel Oil Chemistry.”

In the LRA, the applicant stated that the fuel oil (FO) quality for this program is maintained by monitoring and controlling FO contamination in accordance with the guidelines of American Society for Testing Materials (ASTM) Standards D1796-77 (as specified in ASTM D975-88), D2276-89, and D4057-88. These standards are in accordance with the bases for BSEP Technical Specification Surveillance Requirement 3.8.3.2 for FO testing. Exposure to FO contaminants, such as water and microbiological organisms is minimized by verifying the quality of new oil before its introduction into the storage tanks and by periodic sampling to assure that the tanks are free of water and particulates. The effectiveness of the program is verified using thickness measurement of tank bottom surfaces to ensure that significant degradation is not occurring and to verify the component intended function will be maintained during the extended period of operation.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exceptions and enhancements and the associated justifications to determine whether the AMP, with the exceptions and enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provides an assessment of the AMP’s consistency with GALL AMP XI.M30.

The scope of the Fuel Oil Chemistry Program, as stated in the GALL Report, focuses on managing conditions that cause aging degradation of diesel fuel tank inner surfaces. The program is also designed to reduce the potential of exposure on the tank inner surfaces to FO contaminated with water and microbiological organisms.

The applicant stated that the Fuel Oil Chemistry Program is focused on managing conditions, which can cause aging degradation of the internal surfaces of the in-scope components. The applicant stated that BSEP RS 5.5.9, “Diesel Fuel Oil Testing Program,” requires testing of new and stored FO and includes sampling requirements and acceptance criteria. The staff reviewed this technical specification and determined that it requires sampling and identifies implementing procedures as documented in the staff’s Audit and Review Report. The staff reviewed the procedures and determined that these documents appropriately implement the periodic testing and acceptance requirements for FO at BSEP.

The GALL Report discusses the potential benefit of tank coatings in preventing age degradation and recommends FO quality monitoring for water and microbiological organisms, which can lead to loss of material on tank internal surfaces. The applicant stated that BSEP does not employ coatings for corrosion control. The applicant stated that a procedure specifies the frequency of FO quality and water accumulation monitoring for the in-scope tanks. Microbiological growth is evaluated as needed based upon particulate testing results. The staff reviewed the procedure and determined that it implements a program which specifically identifies FO analysis sampling requirements and limits for new and stored FO and the frequency of testing. The staff determined that the applicant's program adequately monitors FO quality in accordance with the GALL Report.

The GALL Report identifies specific ASTM standards for use such as ASTM Standard D4057 for guidance on oil sampling, ASTM Standards D1796 and D2709 for determination of water and sediment contamination, and ASTM D2276 Method A for determination of particulates. The applicant stated that ASTM Standard D4057 is used for guidance on oil sampling. The applicant also stated that BSEP is in conformance with the GALL Report specified ASTM Standard 1796, but has noted specific exceptions to ASTM Standards D2709 and D2276, which are evaluated below. The applicant stated that multi-level, periodic sampling for the main and 4-day tanks is required. The applicant stated that the saddle tanks are much smaller in volume and subject to less variations in FO properties. Sampling is performed 0.5 inches from the tank bottom with re-sampling, if required, at the 1-inch level. Sampling for the diesel-driven fire pump is performed from the drain line that samples the tank bottom. The staff reviewed the sampling requirements and determined that they meet the recommendations of the GALL Report.

The GALL Report specifies an ultrasonic thickness measurement of tank bottom surfaces to ensure significant degradation is not occurring. The applicant responded that tank internal inspection is limited to the main FO storage tank. The applicant indicates that a particular NDE method for use on this tank has not yet been identified. The applicant further stated that the extent of cleaning and/or surface preparation of the tank bottom will be appropriate for the chosen NDE technique. The applicant responded that BSEP will implement a preventive maintenance activity to inspect the main FO storage tank on a ten-year frequency, which will include a one-time inspection and thickness measurement of the tank bottom, as stated in the UFSAR supplement. On the basis of this review, the staff determined the applicant's inspection plan for the main FO storage tank meets the recommendations of the GALL Report.

In the LRA, the applicant stated the following exceptions to the program elements listed in the GALL Report.

<u>Exception 1 - Scope of Program</u>. The GALL Report identifies the following recommendation for the "scope of program" program element associated with the exception taken:

> The program is focused on managing the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC) of the diesel fuel tank internal surfaces.

<u>Exception</u>: In addition to the storage tanks, the Fuel Oil Chemistry Program is used to manage aging effects on all in-scope components "wetted" by FO. This results in additional materials being within the scope of license renewal beyond those in the GALL Report.

In the LRA, the applicant stated that GALL Report, Section XI.M30, states that the "program is focused on managing the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC) of the diesel fuel tank internal surfaces. The program serves to reduce the potential of exposure of the tank internal surface to FO contaminated with water and microbiological organisms." This reasoning can also be extended to managing the aging of metallic components in a FO environment. The Fuel Oil Chemistry Program also specifies that new fuel be tested in accordance with ASTM D130-94 to assure FO corrosion of copper-alloy components in the diesel system is minimal. These tests and controls ensure that FO system components are exposed to contaminate-free FO with minimal potential to corrode the interior surfaces of carbon steel, copper-alloy and stainless steel components.

During the review and audit, the staff determined that increasing the scope of this AMP to include all components wetted by FO is acceptable and is not considered an exception to the GALL Report. The applicant includes and meets (with noted exceptions and enhancements) the aging management inspections and evaluations for the diesel FO storage tanks, as recommended in the GALL Report. Also, the applicant stated that the condition of the FO storage tanks is considered to be a leading indicator that bounds other materials within the scope of license renewal wetted by FO. In the event that aging degradation is detected in the in-scope FO tanks, appropriate inspections and evaluations of other FO system components will be directed by the Corrective Action Program.

The staff reviewed the procedure for the sampling of FO, as defined in UFSAR, Chapter 1, Table 1-6. The staff agreed that performance of the periodic sampling should detect aging degradation, as discussed by the applicant. Discussions with the applicant's technical staff indicated that the FO lines are primarily carbon steel with some brass fittings. Copper-alloy piping is used for the fire pump, as are some pressure transmitters. The applicant's testing of new fuel in accordance with ASTM D130-94, "Standard Test Method for Detection of Copper Corrosion from Petroleum Products by the Copper Strip Tarnish Test," will allow for copper-containing pipes to be monitored for aging. The staff reviewed this standard and determined that it is applicable to the grade of FO used at BSEP and does include inspections for copper-containing pipes to assess degradation.

The applicant stated that the portions of the FO piping that are buried will be managed by the Fuel Oil Chemisty Program and the Buried Piping and Tanks Inspection Program, which will provide for inspection at least once every ten years. On this basis, the staff determined that the above exception is acceptable.

<u>Exception 2 - Preventive Actions and Corrective Actions</u>. The GALL Report identifies the following recommendation for the "preventive actions" and the "corrective actions" program elements associated with the exception taken:

> The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion.

<u>Exception</u>: The Fuel Oil Chemistry Program does not currently use biocides, stabilizers, and corrosion inhibitors.

In the LRA, the applicant stated, per the GALL Report, Section XI.M30, that the quality of FO is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Fuel is purchased to ASTM D975-88 requirements that address stability and corrosion. Biocides, stabilizers, and corrosion-inhibiting additives have not been used at BSEP. Based on operating history and FO management activities, the addition of biocides, biological stabilizers, and corrosion inhibitors into stored fuel is not necessary; however, the option is retained on an as-needed basis.

Additionally, the applicant stated that a combination of tank design and FO management satisfactorily controls water, particulate, and sediment levels. In support of its position, the applicant stated that, in the evaluation of IN 91-46, the storage tanks are maintained full to minimize internal condensation, and that metal deactivators and corrosion inhibitors are added at the FO refinery by the supplier; no additional additives are used.

The Fuel Oil Chemistry Program is implemented by procedures, as documented in the staff's Audit and Review Report, and were reviewed by the staff, and determined that it implements the sampling procedure for the FO. Inspection frequencies and limits for the FO analysis are specified. Measurements are made for particulate, accumulated water, and biological growth, as needed. In discussions with the applicant's technical staff, the applicant stated that there has been no history of water contamination in the periodic samples taken. The staff reviewed a summary of four years (2000-2004) of particulate testing for the 4-day and main FO storage tanks, which are provided as Attachment 2 to BNP-LR-631, and the data confirm that particulate contamination is below specified levels. Only one sample (in 2001) indicated a high level of particulate, which was subsequently corrected.

The applicant's technical staff stated that BSEP uses Grade No. 2-D fuel oil. The staff reviewed ASTM D975-88 and determined that it is applicable to Grade No. 2-D fuel oil. The staff noted that this specification discusses long-term storage (longer than 12 months after receipt by the user). Section X3.7.1 of ASTM D975-88 states, in part, that "Contamination levels in fuel can be reduced by storage in tanks kept free of water, and tankage should have provisions for water draining. . . . Water promotes corrosion, and microbiological growth may occur at a fuel-water interface." The staff reviewed the applicant's management of FO, including the periodic sampling of stored FO, and determined that the applicant's program is adequate to maintain FO quality. BSEP operating history reviewed by the staff did not show any evidence that water contamination has occurred to any significant degree.

On the basis of the above information, the staff determined that the exception is acceptable.

<u>Exception 3 - Preventive Actions</u>. The GALL Report identifies the following recommendation for the "preventive actions" program element associated with the exception taken:

> Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time.

<u>Exception</u>: Sample trends at BSEP do not warrant periodic cleaning of in-scope tanks. There currently is no program requirement for periodic cleaning of in-scope tanks, because the sampling trends have not indicated that accumulation of water, sediment, or particulates have been a problem.

In the LRA, the applicant stated, sample trends do not warrant periodic cleaning of in-scope tanks. The GALL Report, Section XI.M30, notes that periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the among of water and the length of contact time. The main FO storage tank is a free-standing, outdoor, carbon steel tank with a low point sump design feature to accumulate potential water and sediment. FO chemistry sampling is performed at various levels within the tank, including the sump. The tap for fuel transfer is above the level of the sump insuring that oil transferred to other tanks is free of water and sediment. The DG 4-day FO storage tanks, the DG day tanks (saddle tanks), and the diesel-drive fire pump day tank are all housed in sheltered environments that are not subject to significant water intrusion or condensation. Particulate and water accumulation is checked every 31 days for the main FO storage tank, the DG 4-day FO storage tanks, the diesel generator saddle tanks, and every 92 days for the diesel-driven fire pump tank. In addition, the 4-day and saddle tanks are inspected for water accumulation after every diesel run of greater than one hour. Fuel added to the main FO storage tank is tested for water and sediment during receipt inspection. FO system design, procurement practices, and testing requirements assure that FO is free of water, sediment, and particulates. There currently is no program requirement for periodic cleaning of in-scope tanks because the sampling trends have not indicated accumulation of water.

The staff reviewed documents that implement the periodic sampling of tank contents for water and sediment, as well as the relevant BSEP operating experience, as discussed above. The applicant provided information on the design (presence of sump, size, physical location) of each FO storage tank in the scope of license renewal. The staff viewed photos of the in-scope tanks, as well as sketches on OE&RC-1010 to understand the applicant's bases. The documents reviewed supported the applicant's bases regarding tank design and periodic sampling.

In the LRA, the applicant stated that, based on the FO system design, procurement practices, and testing requirements, the FO is free of water, sediment, and particulates. The staff reviewed a four year sampling of data on sediments in the FO tanks, which confirm the applicant's conclusion that there are no sediments in the tanks. On the basis of this review, the staff determined that the exception from periodic cleaning is acceptable.

The GALL Report also indicates benefits associated with periodic draining. The staff noted that LRA Section B.2.13 includes an exception to periodic cleaning of the FO tanks, but does not specifically address periodic draining. This was not identified as an exception by the applicant in LRA Section B.2.13. In response, the applicant stated that an exception was not claimed because the GALL Report discusses the benefits of FO tank draining in two different contexts, one for the removal of water and the other as an adjunct to cleaning. The applicant stated that corrective actions are taken when water is drained from the tanks during periodic surveillance. Sampling procedures include requirements for water removal (draining) should water be detected. With respect to draining as an adjunct to cleaning, the applicant stated that current plant operating experience has not shown a need to clean the 4-day, saddle, or diesel fire pump tanks. Therefore, draining is not applicable. The applicant decides on cleaning and/or draining the main FO storage tank based on the inspection results obtained.

The staff noted that the applicant periodically samples the in-scope tanks for sediment, contaminants, and water; and takes corrective action upon discovery. The applicant plans to inspect the main FO storage tank, and, if required, drain and clean it prior to the period of extended operation. The relatively small holding volume of the 4-day, saddle, and diesel fire pump tanks tends to result in the FO stored in these tanks being used and refilled periodically during component testing, thus minimizing the potential for water accumulation. On the basis of this review, the staff concluded that the exception from periodic draining is acceptable.

Exception 4 - Parameters Monitored/Inspected and Acceptance Criteria. The GALL Report identifies the following recommendation for the "parameters monitored/inspected" and acceptance recommendation program element associated with the exceptions taken:

> The ASTM Standards D1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 Fm, instead of 0.8 Fm.

Exception: (1) ASTM D2709 is not utilized at BSEP and (2) sampling of particulate contaminants, in accordance with ASTM D2276-89, is performed using a filter with a pore size of 0.8 Fm versus a pore size of 3.0 Fm, as specified in GALL.

In the LRA, the applicant stated the following: (1) NUREG-1801, Section XI.M30, recommends the use of ASTM Standards D1796-97 and D2709-96 as the standard test methods for water and sediment in fuel oils. UFSAR Table 1-6, "Confirmation to NRC Regulatory Guides," summarizes: (1) BSEP commitments to Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators," and (2) BSEP commitments to use ASTM D975-88 as the "Standard Specification for Diesel Fuel Oils" and ASTM D4057-88 for oil sampling. BSEP FO testing is based on ASTM D1796-68 (re-approved 1977), "Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)," in lieu of ASTM D2709, for determining water and sediment. ASTM D1796-68 is considered a more appropriate test for the FO used at BSEP, because (1) it is the method prescribed by ASTM D975-88; and, (2) sampling of particulate contaminants, in accordance with ASTM D2276-89, is performed using a filter with a pore size of 0.8 Fm versus a pore size of 3.0 Fm as specified in NUREG-1801. NUREG-1801, Section XI.M30, recommends that a modified ASTM D2276-00, Method A, be used for determination of particulates. The modification consists of using a filter with a pore size of 3.0 Fm, instead of 0.8 Fm. ASTM D2276 covers the test method for determination of particulate contaminants in aviation turbine fuel using a field monitor. At BSEP, FO is currently sampled for suspended particulate using ASTM D2276-89 as a laboratory test. Therefore, the BSEP testing provides results equivalent or superior to those obtained using a 3.0 Fm pore size as recommended in the GALL Report.

UFSAR Table 1-6 summarizes the applicant's commitments to Regulatory Guide 1.137. These commitments include the use of ASTM D4057-88 as the "Standard Specification For Diesel Fuel Oils," and the use of ASTM D4057-88 for oil sampling. ASTM D975 references the use of ASTM D1796 for determining water and sediment. The staff reviewed this standard and concurs that it is applicable to the grade of FO utilized, and that it does not reference ASTM D2709. The fact that the operating history at BSEP has shown that water, sediment, and particulates are not a problem at BSEP confirms the adequacy of the current method being used.

Based on this, as well as the use of ASTM D975 to meet RG 1.137, the staff determined that the exception to using ASTM D2709 is acceptable.

The staff reviewed the applicant's exception to the filter pore size requirements of ASTM D2276-89. The staff reviewed ASTM D2276 and determined that it provides guidance on the sampling of particulate contamination in aviation fuel. The applicant stated that the exception to using a smaller filter pore size than prescribed in ASTM D2276 will provide equivalent or superior results. The staff agreed with this reasoning and noted that this exception has been accepted at other facilities. The fact that the operating history has shown that particulates are not a problem at BSEP confirms the adequacy of the current method.

Based on the results of the above review, the staff concluded that these exceptions are acceptable.

<u>Exception 5 - Detection of Aging Effects</u>. The GALL Report identifies the following recommendation for the "detection of aging effects" program element associated with the exception taken:

> Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

<u>*Exception*</u>: Tank internal inspection is limited to the main fuel oil storage tank.

In the LRA, the applicant stated the following: tank internal inspection is limited to the main FO storage tank. The GALL Report, Section XI.M30, states:

> Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

At BSEP, internal inspection of the 4-day, saddle, and diesel fire pump tanks will not be performed. Access to these small, elevated tanks is limited, making cleaning and internal inspections impractical. The tanks are sampled for water and particulates from the low point at least quarterly. External ultrasonic inspection of the bottom of these tanks will be performed. BSEP operatingexperience indicates that degradation of these tanks is not occurring. The Fuel Oil Chemistry Program ensures that high quality, non-corrosive, non-biologically-contaminated FO is maintained. Fuel analysis results are monitored and trended to detect degradation of tank internals. Corrective action is initiated as necessary to maintain tank integrity.

The description of GALL AMP XI.M30 recommends that a visual inspection be performed on the internal surfaces of the tanks upon draining to detect potential degradation. The applicant stated that internal inspections of the 4-day, saddle, and diesel fire pump tanks will not be performed, as access to these small, elevated tanks is limited, making cleaning and internal inspection impractical. The staff examined photos of these tanks and agreed that cleaning and a visual inspection would be difficult to perform and obtain meaningful results. In discussions with the staff, the applicant stated that the contents of the tanks are sampled for water and particulates from the low point at least quarterly. The applicant stated that American Petroleum Institute STD-653 allows the substitution of external tank inspections for internal inspections where bottom thickness can be determined by other means. As an alternate, the applicant will perform an external NDE inspection, consisting of a UT thickness measurement, on the bottom of these tanks. The applicant stated that NDE examinations were completed on the emergency fire pump storage tank and several 4-day storage tanks, and no problems relating to tank wall thickness degradation were found.

In response to a staff question during the audit, the applicant described three locations where test results indicated a potential wall thickness less than the typical readings obtained from other locations. The staff reviewed nonconformance report (NCR) 69220 dated 04/23/03, which noted apparent discrepancies with the NDE thickness results on this tank. Three locations indicated a potential wall thickness less than the typical readings taken at various other locations on the tank. Each location indicated a point approximately 0.25 in round and approximately 50 percent of the wall thickness. The typical wall thickness is 0.47 inches with the subject three points reading approximately 0.20 inches. The indications noted were isolated, indicating they were contained, embedded inclusions caused by the plate rolled-steel fabrication process. The report noted that inspection personnel were able to maintain a constant backwall signal during the ultrasonic examination process verifying the three noted indications were not a tank wall degradation issue. The staff concluded that the location and size of these anomalies are adequately documented, indicating that monitoring in accordance with this program will detect any changes during subsequent NDE of the tank bottom.

The staff also agreed that the satisfactory performance of these inspections demonstrates that the external NDE will detect aging degradation of these tanks. The staff also noted that the operating history at BSEP has shown that water, sediment, and particulates have not been a problem, which indicates that aging degradation of the tanks would not be severe and that the inspection technique proposed by the applicant will be adequate.

On the basis of this review, the staff concluded that the exception from internal tank inspections for the 4-day tanks, the emergency diesel fire pump FO tank, and the saddle tanks is acceptable. The acceptability of the applicant’s internal inspection of the main FO storage tank was presented previously.

In the LRA, the applicant stated the following enhancements to this program to make it consistent with the GALL Report.

<u>Enhancement 1 - Detection Of Aging Effects</u>. The GALL Report identifies the following criterion for the “detection of aging effects” program element associated with the enhancement:

> Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom ensures that significant degradation is not occurring.

<u>Enhancement</u>: Thickness measurements of in-scope tanks and an internal inspection of the Main Fuel Oil Storage Tank will be performed under the One-Time Inspection Program (see Commitment Item #9).

The staff noted that the applicant’s exceptions, which are discussed above, are related to this enhancement. The staff concluded that the performance of an internal inspection on the main FO storage tank, and the NDE thickness measurements of in-scope tanks under the One-Time Inspection Program are acceptable. The staff reviewed the program description for the One-Time Inspection Program and determined that it includes the in-scope FO storage tanks. Therefore, the staff concluded that this enhancement is acceptable since it performs the inspections identified and found acceptable for this program.

Enhancement 2 - Monitoring and Trending. The GALL Report identifies the following recommendation for the "monitoring and trending" program element associated with this enhancement:

> Water and biological activity or particulate contamination concentrations are monitored and trended at least quarterly.

Enhancement: Program element "administrative controls" will be enhanced to add a requirement to trend sampling data for water and particulates (see Commitment Item #9).

The applicant stated that water and particulates are monitored at least quarterly, and biological growth evaluations are run on samples from tanks at the discretion of the Environmental and Radiation Control (E&RC) supervisors, if the particulate contamination levels appear to be increasing. The staff confirmed the implementation, by procedure, of the quarterly testing. The procedure also specifies that out-of-specification results will be reported to operations and the system engineer for evaluation and initiation of timely corrective actions, and copies of completed analysis should be sent to the system engineer. The applicant stated that the procedure will be modified to trend the data for water and particulates. The staff reviewed the associated Action Plan which details the implementation action as described in the Audit and Review Report for this enhancement.

The applicant described upgrades that will be implemented to the Fuel Oil Chemistry Program prior to the period of extended operation. BSEP is in the process of upgrading to more contemporary testing standards as follows: ASTM Standards D975-00, D130-94, D1796-97, and D4057-88 will apply. In addition, ASTM D6217-98 will replace ASTM D2276-89 due to issues associated with filter quality control. The new standard prevents filter clogging to the point that a particulate calculation cannot be performed. The GALL Report does not specify specific revisions to ASTM standards; therefore, the staff determined that the applicant's upgrade is acceptable. The change to an alternate standard for particulate testing will not negatively impact the quality of the result, but rather will ensure the performance of particulate calculations. The staff determined that this revision is acceptable.

Based on the above review, the staff concluded that this enhancement is acceptable.

On the basis of its review of the program elements, and on discussions with the applicant's technical staff, the staff concluded that those program elements in Fuel Oil Chemisty Program for which the applicant claims consistency with GALL AMP XI.M30 are consistent with the GALL Report and, therefore, acceptable.

Operating Experience. In the LRA, the applicant stated that:

> Most of the operating experience related to the fuel oil chemistry program involved improvements to the program, procedures, and training by means of self-assessments and other individual initiatives.
>
> BSEP has experienced instances of low fuel flash point in new shipments of oil and one occurrence of discoloration of the fuel oil in a saddle tank. The apparent cause of the fuel oil discoloration was engine lube oil leaking past a degraded oil seal; however, an analysis confirmed that the critical characteristics for the fuel remained within specification. Also, a

leak in a buried fuel oil transfer line was experienced and was attributed to a defect in the external coating of the pipe, leading to localized corrosion and eventual loss of pressure boundary integrity.

A review of plant operating data, conducted by the applicant, did not identify any instances of water in the fuel, particulate contamination, or biological fouling. No FO system component failures attributed to FO contamination have been identified.

The applicant stated that a review of the Corrective Action Program was performed to obtain experience with FO chemistry. The documents reviewed by the applicant included a combination of self-assessment reports, NCRs, and NRC inspections. A number of NCRs resulted in self-identified program improvements that the applicant stated represent a heightened focus on attention to details and process improvement.

Many of the NCRs identified only minor procedural violations which had no impact on system operability. Several NCRs identified potential FO quality issues that could have impacted operability (new FO shipments with lower than acceptable flash points, unannounced FO supplier practices, and color variations). In each instance, the applicant identified the potential issue and determined that operability was not affected. One NCR identified a leak in a FO transfer line between the main FO storage tank and the unloading station. Though this portion of the line is not in-scope for license renewal, it did highlight the importance of inspecting buried pipes for this system, which will be performed under the Buried Piping and Tanks Inspection Program.

The applicant also noted an NRC inspection, October 19, 2001, that reviewed test data sheets and the station acceptance criteria for FO quality to verify that these were consistent with the EDG vendor recommendations and applicable industry standards. All BSEP FO program practices were found to be satisfactory.

The staff selected several adverse condition investigation reports and NCR’s and reviewed the applicant’s conclusions. The applicant concluded that the current practices were adequate, but should be re-evaluated if a different FO supplier is used. No changes were needed to the current FO storage practices for the main FO storage tank, which call for the tank to be filled to heights greater than 20 feet to minimize condensation.

<u>UFSAR Supplement</u>. In LRA Section A.1.1.13, the applicant provided the UFSAR supplement for the Fuel Oil Chemisty Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant’s Fuel Oil Chemistry Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff

also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Reactor Vessel Surveillance Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.14., “Reactor Vessel Surveillance Program,” an existing program that is consistent, with enhancement, with GALL AMP XI.M31.

Appendix H of Part 50 to Title 10, *Code of Federal Regulations,* “Reactor Vessel Material Surveillance Program Requirements,” provides the staff’s requirements for implementing the surveillance programs that are required for a plant’s RV beltline materials. The programs are used to monitor for any changes in fracture toughness properties of a plant’s RV beltline base metal and weld materials as a result of neutron irradiation during the plant’s service lifetime. Appendix H may be accessed at NRC web page:

http://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-apph.html

Section III.C of 10 CFR Part 50, Appendix H, provides the specific requirements related to the implementation of an integrated surveillance program (ISP).

The Boiling Water Reactor Vessel and Internals Project (BWRVIP) has developed an ISP for the RV base metal and weld materials in all operating U.S. BWRs. The BWRVIP provided its ISP in Proprietary Topical Reports BWRVIP-78, “BWR Vessel and Internals Project: BWR Integrated Surveillance Program (ISP) Plan,” and BWRVIP-86, “BWR Vessel and Internals Project: BWR Integrated Surveillance Program (ISP) Implementation.” These proprietary reports are applicable to the design and implementation of the ISP by U.S. BWRs during their first 40-year operating period and were approved by the NRC in its Final Safety Evaluation Report (FSER) to the BWRVIP dated February 1, 2002.

The BWRVIP issued Proprietary Topical Report BWRVIP-116, “BWRVIP Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal,” to address the changes in the ISP that would be necessary to support license renewal applications for operating U.S. BWRs. This report is currently in the process of being reviewed by the NRC for generic acceptability to the U.S. fleet of BWRs.

The applicant’s description for the RVSP discusses how implementation of the program is accomplished to ensure compliance with the requirements of 10 CFR Part 50, Appendix H and conformance with the BWRVIP’s integrated surveillance program provisions and criteria in Topical Report BWRVIP-86, as amended by the pending staff review of Topical Report BWRVIP-116.

Staff Evaluation. During its review, the staff confirmed the applicant’s claim of consistency with the GALL Report. The staff reviewed the enhancement and the associated justifications to determine whether the AMP, with enhancement, remains adequate to manage the aging effects for which it is credited.

The applicant identified the RVSP as an existing ISP that is designed to comply with the requirements for ISPs in 10 CFR Part 50, Appendix H and to conform with recommended guidelines in GALL AMP XI.M31, “Reactor Vessel Surveillance.” The applicant stated that the RVSP is described in UFSAR Section 5.3.1.6.

The applicant stated that the RVSP is based on the BWRVIP’s ISP, as described and discussed in Proprietary Topical Reports BWRVIP-78, “BWR Integrated Surveillance Program (ISP) Plan,” and BWRVIP-86, “BWR Vessel And Internals Project, BWR Integrated Surveillance Program Implementation.” The ISP provides for a number of surveillance capsules to be removed from specified BWRs and to be available for testing during the license renewal period for the BWR fleet. The ISP establishes acceptable technical criteria for capsule withdrawal and testing.

The NRC-approved BWRVIP-78 and BWRVIP-86 for generic applicability to the U.S. BWR fleet in the staff’s FSER to the BWRVIP dated February 1, 2002. The staff approved the application of the BWRVIP’s ISP to the RVs at Units 1 and 2 in the NRC’s safety evaluation (SE) to the applicant, dated January 14, 2004. In the SE of January 14, 2004, the staff agreed that the BWRVIP ISP, as approved in Proprietary Topical Reports BWRVIP-78 and BWRVIP-86-A (the NRC-approved version BWRVIP-86), met the requirements of 10 CFR Part 50, Appendix H and ASTM Standard Practice E185-82 as they apply to the structural integrity and fracture toughness evaluations for the Units 1 and 2 RVs. The staff also agreed that, as a participant in the BWRVIP’s ISP, BSEP would not be required to remove any of the remaining RV surveillance capsules on behalf of the program. Instead, as indicated in Proprietary Topical Report BWRVIP-86-A, the staff concluded that surveillance capsules from other BWRs in the U.S. BWR fleet are acceptable for representing and evaluating the plate and weld materials in the RVs.

Proprietary Topical Reports BWRVIP-78 and BWRVIP-86-A, the staff’s generic FSER of February 1, 2002, and the staff’s SE of January 14, 2004, provide an acceptable basis for approving the RVSP for the current operating periods for the units. To address the impacts of license renewal on the RVSP, the applicant stated that the AMP will be enhanced to address any changes that may be necessary to extend the applicability of the AMP through the periods of extended operation for BSEP. The staff discussed and evaluated the applicant’s enhancement of the RVSP in the “Enhancements and Commitments for the RVSP” section of this evaluation.

Enhancement: The applicant stated that the BWRVIP’s ISP has been enhanced to address the impact of license extension on the ISP for BWR facilities and that the enhanced program is described and discussed in Proprietary Topical Report BWRVIP-116. The applicant stated that the RVSP will incorporate the following enhancement:

> BSEP plans to continue using the Integrated Surveillance Program during the period of extended operation by implementing the requirements of BWRVIP-116, which is under NRC review at this time.

Proprietary Topical Report BWRVIP-116 was submitted by the BWRVIP to the NRC in 2003 to address the impacts of license extension on the ISP’s proposed surveillance capsule withdrawal schedule and to determine whether additional ISP capsules would need to be designated for addition to the proposed surveillance capsule withdrawal schedule. Proprietary Topical Report BWRVIP-116 is currently in the process of being reviewed by the staff. The applicant has acknowledged that the NRC’s review of Proprietary Topical Report BWRVIP-116 is still pending; therefore, it provided the Commitment **Item #22** for the RVSP in BSEP serial letter, BSEP-04-0006, dated October 18, 2004:

> The Reactor Vessel Surveillance Program will be enhanced to ensure that any additional requirements that result from the NRC review of Boiling Water Vessel [and] Internals Program (BWRVIP)-116 are addressed prior to the period of extended operation.

The applicant's commitment will ensure that the any changes to the withdrawal schedule requirements for the ISP, as approved in the NRC's acceptance of BWRVIP-116 and found to be applicable to the applicant's RVs, will be incorporated into the RVSP. Since this enhancement of the RVSP has been included as a commitment for the LRA, the staff concluded that the applicant's commitment for the RVSP will ensure that the monitoring of the BSEP-1/2 RVs for neutron irradiation embrittlement will account for the impacts of aging on the embrittlement trends for the vessels and will be implemented in accordance with Topical Report BWRVIP-116 pending staff approval. Based on this evaluation, the staff concludes that RVSP, as enhanced by Commitment **Item #22** on the LRA, is acceptable.

Operating Experience. In the "operating experience" program element for the RVSP, the applicant stated that the RVSP is an ISP which is based on Proprietary Topical Reports BWRVIP-78 and BWRVIP-86-A and that generic approval for using these industry initiative reports was granted by the NRC in its FSER to the BWRVIP dated February 1, 2000. The applicant stated that plant-specific approval of the RVSP was granted for BSEP in the NRC's SE dated January 14, 2004. The staff confirmed that these topical reports and NRC evaluations are applicable to the staff's approval of the RVSP.

The RVSP is an integrated surveillance program that has been proposed by the BWRVIP on behalf of BWRs in the U.S. and that has been approved by the staff for implementation by the utilities that own BWRs participating in the BWRVIP's monitoring programs. The current NRC-approved program for BSEP does not require the applicant to remove the BSEP RV surveillance capsules for testing. Thus, there is not any BSEP-specific operating experience that is directly applicable to the RV structural integrity assessments for BSEP. Instead the plant is relying of generic test results from surveillance tests performed on other capsules that have been removed from other U.S. BWR RVs. The surveillance test results from the generic integrated surveillance program, which was approved in the staff's SE dated January 14, 2004, provides acceptable generic operating experience that is applicable to the RV integrity assessments for the BSEP RVs (Refer to the staff's assessment in SER Section 4.2 on the applicant's TLAAs for managing neutron irradiation embrittlement of the RV and internal components).

UFSAR Supplement. 10 CFR 54.21(d) requires that the UFSAR supplement for a facility LRA must contain a summary description for each AMP and TLAA that is proposed for aging management. The applicant provided the following UFSAR supplement summary description for the RVSP:

> **A.1.1.14 Reactor Vessel Surveillance Program**
>
> The Reactor Vessel Surveillance Program is mandated by 10 CFR 50, Appendix H. The Program is an Integrated Surveillance Program, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.C, that is based on requirements established by the BWR Vessel and Internals Project reports.
>
> This Program will be enhanced to ensure that any additional requirements that result from the NRC review of BWRVIP-116 are addressed prior to the period of extended operation. The enhanced Program will be consistent with the corresponding program described in NUREG-1801.

The applicant's UFSAR supplement summary description for the RVSP is consistent with the description of the AMP that is given in LRA Section B.2.14. The staff found that the UFSAR supplement summary description is acceptable because it accomplishes the following regulatory functions:

(1) The summary description indicates that the RVSP is an ISP that is designed to comply with the requirements for ISPs in Section III.C. of 10 CFR Part 50, Appendix H. This is consistent with the staff's approval of the RVSP for the current operating periods for BSEP, as documented in the staff's SE dated January 14, 2004, and confirms that the staff has approved the RVSP for implementation.

(2) The summary description indicates that the RVSP will be enhanced to address the need to amend the integrated withdrawal schedule for the surveillance capsules representing the BSEP RVs as potentially impacted by the staff's pending review of Proprietary Topical Report BWRVIP-116. This is acceptable because it is consistent with the staff's process for reviewing and approving the BWRVIP's ISP, as impacted by license renewal, and because the applicant has incorporated a commitment in the LRA to ensure that this will be done.

In the most recent staff-approved version of the ISP, the RV surveillance capsules from BSEP have not been designated for removal and testing to support the ISP. However, as addressed in Section III.C.1.d of 10 CFR Part 50, Appendix H, and in the staff-approved BWRVIP ISP, maintaining adequate contingencies to support potential changes to the program is an important part of any ISP. The staff plans to discuss with the BWRVIP the issue of maintenance of standby capsules for future use. Until there is more detailed guidance regarding the treatment of standby capsules, the staff imposed the following license condition to ensure that any surveillance capsules removed from BSEP, without the intent to test them, are maintained in a condition which would permit their future use, including use during the period of extended operation, if necessary:

> The integrated surveillance program to be implemented will be the most recent revision of the staff-approved Boiling Water Reactor Vessel and Internals Project Integrated Surveillance Program. If any surveillance capsules are removed from the Brunswick, Unit 1 and 2, reactor vessels (RVs) without the intent to test them, these capsules must be stored in manner which maintains them in a condition which would support re-insertion into the Brunswick RVs, if necessary.

The imposition of this license condition is consistent with actions that the staff has taken with other, recent license renewal applicants with respect to the control of "standby" RV surveillance capsules.

<u>Conclusion</u>. On the basis of its review of the applicant's program, the staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 One-Time Inspection Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.15, "One-Time Inspection Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions and enhancement, with GALL AMP XI.M32, "One-Time Inspection."

In the LRA, the applicant stated that this program uses one-time inspections to verify the effectiveness of an AMP and confirm the absence of an aging effect. The program includes inspections specified by the GALL Report, as well as plant-specific inspections where inspection results can reasonably be extrapolated through the period of extended operation. The One-Time Inspection Program is credited for aging management of the following structures/components: water chemistry verification; fuel oil tanks in scope for license renewal; control rod drive pump casings, orifices, and piping; control rod drive hydraulic control unit filters; recirculation coolant flow elements and main steam flow limiters (cast austenitic stainless steel); RHR throttle valves; internal surfaces of piping in moist environments; internal surfaces of relief valve discharge lines, piping and valves; carbon steel, copper-alloy, and elastomeric components; internal surfaces of carbon steel components (not covered by the Preventive Maintenance Program); intake and exhaust silencers; internal surfaces of components; tanks, piping, valves; uncoated component supports and portions of the torus liner; interior surfaces of SRV discharge piping (tail pipes); and components exposed to raw water.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and enhancement and the associated justifications to determine whether the AMP, with the exception and enhancement, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP's consistency with GALL AMP XI.M32.

In the LRA, the applicant stated the purpose of the One-Time Inspection Program is to inspect the current condition of a structure/component to predict its aging-related condition through the license renewal period. In accordance with the GALL Report, the One-Time Inspection Program verifies the effectiveness of an existing AMP; that is, that unacceptable degradation is not occurring; and determines the need for additional aging management for structures/components currently not managed by other AMPs. The program includes a verification of the effectiveness of both the Water Chemistry Program and Fuel Oil Chemistry Program. The program also includes a number of non-GALL inspections based on plant-specific AMRs. The staff compared the scope of the One-Time Inspection Program to that described in the BSEP calculation for the Water Chemistry Program and Fuel Oil Chemistry Program, as discussed in the staff's Audit and Review Report. For both programs, the scope and methods were found to be consistent with the One-Time Inspection Program.

As documented in the staff's Audit and Review Report, the applicant stated that each structure/component inspected under its One-Time Inspection Program is evaluated against a unique set of considerations based on determination of sample size, based on assessment of material, environment, plausible aging effects and operating experience; identification of inspection locations, based on the aging effect; determination of the examination technique, including acceptance criteria that would be effective; evaluation of the need for follow-up examinations to monitor progression of aging degradation; and corrective actions, including expansion of sample size and locations. The applicant further stated that inspection methods will include a variety of NDE methods (visual, volumetric, and surface techniques) performed by qualified personnel and will use applicable codes and standards in accordance with LRA Appendix B quality assurance requirements. The staff determined that the inspection techniques, when evaluated against applicable codes and standards, are consistent with the recommendations in the GALL Report.

The GALL Report recommends a representative sample of the system population to be chosen to focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The applicant stated the inspection sample size will be based on several considerations, including accessibility, leading or bounding locations, safety significance, severity of operating conditions, and design margins. The applicant further stated that, where feasible, it is acceptable to use like material and environment combinations in alternate components/systems for verification of the Water Chemistry Program. Also the one-time inspection for AMP effectiveness will include: determination of the sample size, based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; identification of the inspection locations in the system or component, based on the aging effect; determination of the examination technique, including acceptance criteria that would be effective for managing the particular aging effect; and an evaluation of the need for a follow-up examination to monitor the progress of any aging.

The applicant stated that system boundaries can be arbitrary relative to service environments and materials. Therefore, components in one system can be considered to be representative of components in another system when determining sample population. The applicant stated that this will not be used as a basis to reduce sample size and will include at least one representative component per system.

The applicant stated that, in accordance with the GALL Report, the one-time inspections will be completed before the end of the current operating license. The inspections will be scheduled to minimize the impact on plant operations. The applicant stated that the inspections will be scheduled during the mid-part of the fourth quarter of the current licensing period, and the results will be evaluated in accordance with site procedures. The staff determined that this is consistent with the recommendations in the GALL Report.

The staff noted that the GALL Report recommends either an appropriate AMP to manage the aging effects, plus a one-time inspection to confirm the effectiveness of the AMP, or the use of periodic inspections. The staff asked the applicant to provide the technical bases for concluding that a one-time inspection would provide adequate assurance that aging degradation will not occur during the period of extended operations for those instances in which the one-time inspection alone is credited by the applicant. The applicant stated that the BSEP program is consistent with the GALL Report since they are using the Water Chemistry Program, Fuel Oil Chemistry Program, and One-Time Inspection Program for verification of effectiveness. The applicant further stated that, for cases where a one-time inspection is credited without an accompanying AMP, one of the following applies: (a) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring or that the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

The applicant further noted that 30 years of operational experience will have accumulated before inspections are performed and that this time period will be sufficient for the aging effects to manifest themselves. The One-Time Inspection Program will verify the correctness of these expectations or serve as a basis for subsequent corrective actions. The staff determined that this approach is consistent with the recommendations of the GALL Report and is acceptable.

The applicant stated that this program is not intended to be a monitoring or trending program. Any degradation encountered will be evaluated, corrected, and, if required, monitored and trended in accordance with the Corrective Action Program. Any indications or degradation conditions will be evaluated. The staff, in its review of the Diesel Fuel Oil Program, confirmed that one-time thickness inspections of in-scope tanks will be compared against as-built dimensions. The staff determined that the applicant's approach is consistent with the recommendations in the GALL Report, and is acceptable.

In the LRA, the applicant stated the following exception to the program elements in the GALL Report.

<u>Exception 1 - Scope of Program</u>. The GALL Report identifies the following recommendation for the "scope of program" program element associated with the exception taken:

> The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is to verify the effectiveness of the AMPs...have been identified in the ...(GALL) Report. Examples include small bore piping in the reactor coolant system or feedwater system components in boiling water reactors (BWRs).
>
> <u>Detection Of Aging Effects</u>. The GALL Report identifies the following for "detection of aging effects" program element associated with the exception taken:
>
> For small-bore piping, actual inspection locations are based on physical accessibility, exposure levels, NDE techniques, and locations identified in Nuclear Regulatory Commission (NRC) Information Notice (IN) 97-46.

<u>Exception</u>: BSEP does not utilize the One-Time Inspection Program activity specified in the GALL Report for detection of cracking in small-bore Class 1 piping. Cracking of this piping will be detected and managed by the combination of the ASME Section XI, Subsection IWB, IWC and IWD Program supplemented by the Water Chemistry Program. This is justified by the evaluations performed during implementation of the RI-ISI Program and by operating experience which shows a lack of indications that cracking of this piping is occurring. In support of the submittal, evaluations of degradation mechanisms were performed and demonstrated that no locations had a high failure potential on small bore pipe due to thermal stratification, cycling, and striping (TASCS) and thermal transients (TT). The RI-ISI evaluations considered lines greater than 1-inch in diameter. For lines 1-inch and smaller, cracking due to thermal loadings was evaluated and dispositioned as not applicable. Cracking due to mechanical loadings was evaluated by a review

of plant-specific operating experience; no relevant operating experience was found. The risk associated with cracking due to SCC of these lines is bounded by those components selected for inservice inspection as part of RI-ISI Program. Therefore, the current inspection methods as detailed in the ASME Section XI, Subsection IWB, IWC and IWD Program supplemented by the Water Chemistry Program will manage cracking of small bore piping systems.

The staff notified the applicant that the NRC does not recognize a current RI-ISI evaluation as an acceptable technical basis for excluding inspection of small bore piping for license renewal and requested the applicant to identify a program that is consistent with the GALL Report.

In its initial response during the audit, the applicant stated that the One-Time Inspection Program will be revised to include verification of aging management program effectiveness on pipes and fittings less than four inches within ASME Code Class 1 boundaries. The response also stated that the program will include piping components that (1) are large enough such that their failure might be beyond the capability of normal reactor makeup; and, (2) have been evaluated as being susceptible to the cracking mechanisms noted in the GALL Report Section IV.C1.1.13.

Regarding criterion (1), the applicant stated that, per 10 CFR 50.55a(c)(2), components that are connected to the RCPB and are part of the reactor coolant pressure boundary can be excluded from the requirements set forth in Code Class 1 components, provided that in the event of a postulated failure of the component during normal reactor operation, the reactor can be shut down and cooled in an orderly manner assuming makeup is provided by the reactor coolant makeup system, pursuant to 10 CFR 50.55a(c)(2).

Regarding criterion (2), the applicant stated that item IV.C1.1.13 in the GALL Report addresses aging management requirements for BWR RCPB piping and fittings less than four inches and identifies crack initiation and growth/stress corrosion cracking, IGSCC, and thermal and mechanical loading as aging mechanisms of concern. The applicant stated that a similar analysis has been performed for BSEP and concludes that certain lines are not susceptible to thermal and mechanical loading based on design or service considerations. Similarly, BSEP AMRs have concluded that carbon steel piping in this category is not susceptible to SCC. Piping components that are evaluated and determined not susceptible to the cracking mechanisms noted in the GALL Report, item IV.C1.1.13, will be exempt from one-time inspections for this aging mechanism.

The applicant further stated that the One-Time Inspection Program will be revised to include the following descriptions of crack detection. The inspection includes a representative sample of the population, and, where practical, focuses on the bounding components or components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For small bore piping, actual inspection locations are based on physical accessibility, exposure levels, NDE techniques, and locations identified in IN 97-46. Combinations of NDE (including visual, ultrasonic, and surface techniques) will be performed by qualified personnel consistent with the ASME Code and 10 CFR Part 50, Appendix B. For applicable small bore piping, a plant-specific destructive examination of replaced piping (due to plant modification) or NDE that permits inspection of inside surfaces will be performed. Follow-up of unacceptable inspection findings will result in expansion of sample size and locations. These inspections will be completed before the end of the current operating license period.

The applicant concluded its response by stating that the Water Chemistry Program and ASME Section XI (IWB, IWC, and IWD) Program will be credited for aging management of small bore piping. These components will be subject to physical leakage inspections under ASME Section XI the One-Time Inspection Program will be used to verify the effectiveness of these programs.

After review and discussion of the applicant's initial response by the staff, the applicant revised its response criterion (1) above to state the following (see Commitment Item #11).

> BSEP will revise the One-Time Inspection Program to include verification of aging management program effectiveness on less than four inch piping and fittings within ASME Code Class 1 boundaries. The BSEP One-Time Inspection Program will be revised to include the following description of how cracking will be detected.
>
> The inspection includes a representative sample of the population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For small-bore piping, actual inspection locations are based on physical accessibility, exposure levels, NDE techniques, and locations identified in NRC Information Notice 97-46, as applicable.
>
> Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. For small-bore piping less than NPS 4 inches, including pipe, fittings, and branch connections, a plant-specific destructive examination of replaced piping due to plant modifications or NDE that permits inspection of the inside surfaces of the piping will be performed to ensure that cracking has not occurred.
>
> Follow-up of unacceptable inspection findings includes expansion of the inspection sample size and locations.
>
> With respect to inspection timing, the one-time inspection is to be completed before the end of the current operating license.
>
> BSEP credits the Water Chemistry Program and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (for leakage inspections) for aging management of cracking in less than 4 inch NPS Class 1 piping components. These components will be subject to physical inspections for leakage under the latter program. Additionally, the One-Time Inspection Program will be used, as described above, to verify the effectiveness of these programs.

Upon inclusion of small bore piping in the One-Time Inspection Program as described above, the program will be consistent with the program description found in the GALL Report, AMP XI.M32.

Details regarding the implementation of the one-time inspections including identification of specific sampling techniques and inspection locations, will be formalized prior to the end of the current license term.

The staff determined that the applicant's revised commitment for small bore piping inspection under the One-Time Inspection Program is acceptable on the basis that the applicant has committed to develop a program that is consistent with the GALL Report.

In the LRA, the applicant stated the following enhancement to this program to make it consistent with the recommendations in the GALL Report:

Enhancement - Scope of Program. The GALL Report identifies the following recommendation for "scope of program" program element associated with the enhancement:

> The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation.

Enhancement: Procedural controls will be developed to track, implement, complete, and report activities associated with one-time Inspections.

The applicant stated that this is an enhancement because it identifies activities that represented a change to existing processes and procedures in order to be consistent with the recommendations of the GALL Report. In the case of this enhancement, the applicant committed to develop procedural controls to implement the inspection activities (see Commitment Item #11).
The staff determined that the applicant's proposed enhancement is acceptable on the basis that procedural controls are essential to ensuring that the effects of aging will be adequately managed.

On the basis of its review of the program elements, and discussions with the applicant's technical staff, the staff concluded that those program elements in the One-Time Inspection Program for which the applicant claims consistency with GALL AMP XI.M32 are consistent with the GALL Report and, therefore, acceptable.

Operating Experience. In the LRA, the applicant stated that the One-Time Inspection Program is a new program. The BSEP aging management review process ensures that one-time inspections have been prescribed and developed with consideration of plant and industry operating experience.

The staff determined that this program will be effective in accomplishing the objectives of the One-Time Inspection Program, upon revision, on the basis that it is consistent with GALL AMP XI.M32. The staff reviewed the implementation of the One-Time Inspection Program in other programs (fuel oil chemistry and water chemistry) and determined that the inspections to be performed and the data to be obtained met the guidance of GALL AMP XI.M32.

The staff recognizes that the Corrective Action Program, which captures internal and external plant operating experience issues, will ensure that operating experience is reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging are adequately managed.

UFSAR Supplement. In LRA Section A.1.1.15, the applicant provided the UFSAR supplement for the One-Time Inspection Program, which states that:

(pp) The One-Time Inspection Program uses one-time inspections to verify the effectiveness of an aging management program and confirm the absence of an aging effect. The program scope includes water chemistry and fuel oil chemistry verifications specified by the GALL Report, as well as plant specific inspections

(qq) Prior to the period of extended operation, the One-Time Inspection Program will be enhanced by the addition of procedural controls for implementation and tracking activities associated with the program.

The staff reviewed the UFSAR Supplement for the One-Time Inspection Program, and noted that a revision is necessary to specifically identify that the scope of the program also includes small-bore Class 1 piping, as specified in the GALL Report. The staff requested that the applicant identify all required revisions to the BSEP LRA in order to be consistent with its new commitment to include small bore Class 1 piping in the scope of the One-Time Inspection Program (see Commitment Item #11). As documented in the Audit and Review Report, the applicant identified the following revision to the LRA as applicable to the UFSAR supplement:

> A.1.1.15 – The description of the One Time Inspection Program will reflect that the One-Time Inspection Program includes inspection of small bore Class 1 piping for cracking.

The staff reviewed this section and determined that, with the additional commitment, the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's One-Time Inspection Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Selective Leaching of Materials Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.16, "Selective Leaching of Materials Program." In the LRA, the applicant stated that this is a new program that is consistent, with exception, with GALL AMP XI.M33, "Selective Leaching of Materials."

In the LRA, the applicant stated that this program ensures the integrity of components (such as piping, pump casings, valve bodies, and heat exchanger components) made of cast iron, brasses, and aluminum bronze exposed to a raw water, treated water, moisture-laden air or buried environment (see Commitment Item #12). The program will define a one-time examination methodology and acceptance criteria that will be implemented by the work management process using a qualitative determination of selected components that may be susceptible to selective leaching. Confirmation of selective leaching will be performed with a metallurgical evaluation or other testing methods.

The applicant also stated that the examinations will determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function(s) for the period of extended operation. A sample population will be selected for the inspections which will be completed prior to commencing the period of extended operation (see Commitment Item #12). Evidence suggesting the presence of selective leaching will result in expanded sampling, as appropriate, and engineering evaluation.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and the associated justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP's consistency with GALL AMP XI.M33.

In the LRA, the applicant stated the following exception to program elements in the GALL Report:

The GALL Report identifies the following recommendation for "scope of program," "preventive actions," "parameters monitored/inspected," "detection of aging effects," and "monitoring and trending" program elements associated with the exception taken:

> Scope of Program. This AMP determines the acceptability of the components that may be susceptible to selective leaching and assess their ability to perform the intended function during the period of extended operation. These components include piping, valve bodies and bonnets, pump casings, and heat exchanger components. The materials of construction for these components may include cast iron, bronze, or aluminum-bronze. These components may be exposed to raw water, treated water, or groundwater environment. The AMP includes a one-time hardness measurement of a selected set of components to determine whether loss of material due to selective leaching is not occurring for the period of extended operation.
>
> Preventive Actions. The one-time visual inspection and hardness measurement is an inspection/verification program; thus, there is no preventive action.
>
> Parameters Monitored/Inspected. The visual inspection and hardness measurement is to be a one-time inspection. Because selective leaching is a slow acting corrosion process, this measurement is performed just before the beginning of the license renewal period unacceptable inspection findings included expansion of the inspection sample size and location.
>
> Detection of Aging Effects. The one-time visual inspection and hardness measurement includes close examination of a select set of components to determine whether selective leaching has occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation. One

acceptable procedure is to visually inspect the susceptible components closely and conduct Brinell Hardness testing on the inside surfaces of the selected set of components to determine if service leaching has occurred. If it is occurring an engineering evaluation is initiated to determine acceptability of the affected components for further service.

Monitoring and Trending. There is no monitoring and trending for the one-time visual inspection and hardness measurement.

Exception: A qualitative determination of selective leaching will be used in lieu of Brinell hardness testing for components within the scope of this program. The exception involves the use of examinations, other than Brinell hardness testing, identified in GALL AMP XI.M33. The exception is justified, because (1) hardness testing may not be feasible for most components due to form and configuration (i.e., heat exchanger tubes); and, (2) other mechanical means, (i.e., scraping or chipping provide an equally valid method of identification).

The staff reviewed the applicant’s exception and determined that it is justified on the following basis: (1) hardness testing is not feasible for most components due to form and configuration; (2) other mechanical means (i.e., resonance when struck by another object, scraping, or chipping) will be used and provide an equally valid method of identification; and, (3) the applicant’s program will include one-time inspections and qualitative determinations of selected components that may be susceptible to selective leaching. The staff considered the applicant’s justification to be reasonable and acceptable.

On the basis of its review of the program elements, and discussions with the applicant’s technical staff, the staff concluded that those program elements in the Selective Leaching of Materials Program for which the applicant claims consistency with GALL AMP XI.M33 are consistent with the GALL Report and, therefore, acceptable.

Operating Experience. In the LRA, the applicant stated that there is operating experience to indicate that selective leaching of materials has occurred. Evidence of selective leaching has resulted in engineering evaluation and/or component replacement. As this is a new program, there is no operating experience to confirm program effectiveness.

During the audit the staff asked the applicant how operating experience is captured. The applicant indicated that the plant procedure for operating experience increases personnel’s awareness of plant and industrial operating experience so that lessons learned can be used to adjust its AMP, as necessary. In its procedure, the applicant stated that it provides guidance for using, sharing, and evaluating operating experience at NGG sites, as well as promoting the identification and transfer of lessons learned by industry. The staff reviewed the applicant’s procedure and determined that it is acceptable.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the staff concluded that the Selective Leaching of Materials Program will adequately manage the aging effects for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.16, the applicant provided the UFSAR supplement for the Selective Leaching of Materials Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Selective Leaching of Materials Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.17, "Buried Piping and Tanks Inspection Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions, with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

In the LRA, the applicant stated that this program will manage aging effects on the external surfaces of carbon steel, stainless steel, and cast iron piping components that are buried in soil or sand. The aging effects/mechanisms of concern are loss of material due to general, pitting, and crevice corrosion and MIC. To manage the aging effects, this program includes (1) preventive measures (e.g., coatings and wrappings required by design) to mitigate degradation; and, (2) visual inspections of external surfaces of buried piping components, when excavated, for evidence of coating damage and degradation. The periodicity of these inspections will be based on plant operating experience and opportunities for inspection such as scheduled maintenance work requiring excavation. Any evidence of damage to the coating or wrapping, such as perforations, holidays, or other damage, will cause the protected components to be inspected for evidence of loss of material. The results of visual inspections will be reviewed and evaluated to identify susceptible locations that may warrant further inspections. This program assures that the effects of aging on buried piping components are being effectively managed for the period of extended operation.

The applicant also stated that this program will be implemented prior to the period of extended operation and will include procedural requirements to (1) ensure that an appropriate as-found pipe coating and material condition inspection is performed whenever buried piping within the scope of this program is exposed; (2) add precautions concerning excavation and use of backfill to the excavation procedure to include precautions for license renewal piping; (3) add a requirement that coating inspection shall be performed by qualified personnel to assess its condition; and, (4) add a requirement that a coating engineer or other qualified individual should assist in evaluation of any coating degradation noted during the inspection (see Commitment Item #13).

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exceptions and the associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP elements' consistency with GALL AMP XI.M34.

In the LRA, the applicant stated the following exceptions to program elements in the GALL Report.

Exception 1 - Scope of Program. The GALL Report identifies the following guidance for the "scope of program" program element associated with the exception taken:

> The program relies on preventive measures such as coating and wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried carbon steel piping and tanks. Loss of material in these components, which may be exposed to aggressive soil environment, is caused by general, pitting, and crevice corrosion, and microbiologically influenced corrosion (MIC). Periodic inspections are performed when the components are excavated for maintenance or for any other reason.

Exception: In addition to carbon steel piping components, buried stainless steel and cast iron piping components are considered an acceptable exception to the limited material scope delineated by the GALL Report program. The aging effects are managed by use of external coatings and inspections regardless of the piping material. This program includes no buried tanks.

The applicant expanded the scope of its Buried Piping and Tanks Inspection Program to include stainless steel and cast iron piping components. The staff determined that this expansion of the scope does not reduce the effectiveness of the program for managing the aging of carbon steel piping and tanks. On the basis of its review of documents, and discussions with the applicant's technical staff, the staff concluded that the exception is acceptable.

Exception 2 - Detection of Aging Effects. The GALL Report identifies the following recommendation for "detection of aging effects" program element associated with the exception taken:

> Periodic inspection of susceptible locations to confirm that coating and wrapping are intact. The inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. Because the inspection frequency is plant specific and also depends on the plant operating experience, the applicant's proposed inspection frequency is to be further evaluated for the extended period of operation.

Exception: The GALL Report refers to periodic inspections with a scheduled frequency; however, BSEP intends to inspect buried piping excavated during maintenance activities. Excavating components solely to perform inspections poses undue risk of damage to protective coatings. Operating experience indicates that the frequency of excavating buried piping for maintenance activities is sufficient to provide reasonable assurance that the effects of aging will be identified prior to the loss of intended function.

The staff noted that the applicant plans to perform periodic buried piping inspections that will be opportunistic inspections performed during maintenance activities. The staff informed the applicant that opportunistic inspections qualify; however, there must also be a commitment to perform periodic inspections at least once every ten years during the license extension period. Opportunistic inspections can qualify for the periodic inspections.

As documented in the staff's Audit and Review Report, the applicant committed to revise the Buried Piping and Tanks Inspection Program to perform periodic inspections of buried piping (see Commitment Item #13). The applicant stated that opportunistic inspections may be used to satisfy inspection requirements, but in no case will the frequency of inspection exceed 10 years.

The staff reviewed the applicant's response and determined that, with the commitment to perform periodic inspections at least once every 10 years, the applicant's program is consistent with the GALL Report.

On the basis of its review of the program elements, and discussions with the applicant's technical staff, the staff concluded that those program elements in the Buried Piping and Tanks Inspection Program for which the applicant claims consistency with GALL AMP XI.M34 are consistent with the GALL Report and, therefore, acceptable.

<u>Operating Experience</u>. In the LRA, the applicant stated that industry operating experience has shown that carbon steel and cast iron buried components have experienced corrosion degradation. Critical areas include the interface at which the component transitions from above ground to below ground. This is an area where coatings are often missing or damaged.

The applicant also stated that leaks have occurred in buried piping components and have been repaired, which demonstrates that leaks have been detected and that appropriate corrective actions have been taken, demonstrating the applicant's ability to ensure no loss of component intended function in the period of extended operation. BSEP conducts pressure tests of safety-related service water system buried piping to ensure adequate flow delivery and technical specification operability.

The applicant concluded that, based on plant operating experience, scheduled, periodic excavations of buried piping for inspection are not warranted. As additional operating experience is obtained, lessons learned may be used to adjust this program.

The staff asked the applicant how operating experience is captured. The applicant indicated that plant procedure, Operating Experience Program, is used to increase personnel's awareness of plant and industrial operating experience so that lessons learned can be used to adjust its AMP, as necessary. In its procedure, the applicant stated that it provides guidance for using, sharing, and evaluating operating experience at NGG sites as well as promoting the identification and transfer of lessons learned by the industry. The staff reviewed the applicant's procedure and determined that the procedure is acceptable.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the staff concludes that the applicant's Buried Piping and Tanks Inspection Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

<u>UFSAR Supplement</u>. In LRA Section A.1.1.17, the applicant provided the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The staff reviewed this section and determined

that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Buried Piping and Tanks Inspection Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 ASME Section XI, Subsection IWL Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.2.19, "ASME Section XI, Subsection IWL Program " In the LRA, the applicant stated that this is an existing program that is consistent, with exception, with GALL AMP XI.S2, "ASME Section XI, Subsection IWL Program."

In the LRA, the applicant stated that this program consists of periodic visual inspection of reinforced concrete containment structures. The program is in accordance with ASME Code, Section XI, Subsection IWL, 1992 Edition, 1992 Addenda, and is credited for the aging management of accessible and inaccessible, pressure-retaining, primary containment concrete. The BSEP concrete containments do not utilize a post-tensioning system; therefore, the ASME Code, Section XI, Subsection IWL requirements associated with a post-tensioning system are not applicable.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and the associated justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP's consistency with GALL AMP XI.S2.

In LRA Section B.2.19, the applicant stated an exception to an element of the AMP in the GALL Report, as follows.

Exception - Scope of Program. The GALL Report identifies the following recommendation for the "scope of program" program element associated with the exception taken:

> Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and unbonded post-tensioning systems of Class CC containments, as defined by CC-1000.

Exception: The BSEP concrete containments do not utilize a post-tensioning system. Therefore, the ASME Section XI, Subsection IWL requirements associated with a post-tensioning system are not applicable and are excluded from the program.

Since the containment is a reinforced concrete design, and not a prestressed concrete design, the provisions of IWL for inspection of unbonded post-tensioning systems are not applicable to BSEP.

On the basis of its review of the above exception and discussions with the applicant's technical staff, the staff concluded that the exception stated by the applicant for the ASME Section XI, Subsection IWL Program to the program element for GALL AMP XI.S2 is acceptable.

Operating Experience. In the LRA, the applicant stated that the ASME Section XI, Subsection IWL Program is implemented and maintained in accordance with the general requirements for engineering programs. This provides assurance that the programs (1) are effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; (2) have qualified personnel assigned as program managers with authority and responsibility to implement the program; (3) have adequate resources committed to program activities; and (4) are managed in accordance with plant administrative controls.

The applicant also stated that plant-specific operating experience has identified numerous assessments, performed on both a plant-specific and corporate basis, dealing with program development, effectiveness, and implementation. The ASME Section XI, Subsection IWL Program is continually being upgraded based upon industry and plant-specific experience. Additionally, plant operating experience is shared between Progress Energy sites through regular peer group meetings, a common corporate sponsor, and outage participation of program managers from other Progress Energy sites.

The staff did not identify any documented occurrences of containment concrete degradation in its review of plant-specific operating experience. Based on discussions with the applicant's technical staff, there have been no occurrences of containment concrete degradation observed.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff found that the applicant has adequately considered operating experience, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.1.19, the applicant provided the UFSAR supplement for the ASME Section XI, Subsection IWL Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's ASME Section XI, Subsection IWL Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exception and the associated justifications, and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 ASME Section XI, Subsection IWF Program

Summary of Technical Information in the Application.This AMP is described in LRA Section B.2.20, “ASME Section XI, Subsection IWF Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with enhancement, with GALL AMP XI.S3, “ASME Section XI, Subsection IWF.”

In the LRA, the applicant stated that this program provides for visual examination of component and piping supports within the scope of license renewal for loss of material and loss of mechanical function. The program is implemented through plant procedures, which provide for visual examination of inservice inspection Class 1, 2, 3, and MC supports in accordance with the requirements of ASME Section XI, Subsection IWF, 1989 Edition, and ASME Code Case-491.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancement and the associated justifications to determine whether the AMP, with the enhancement, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provide an assessment of the AMP elements' consistency with GALL AMP XI.S3.

In the LRA, the applicant stated the following enhancement to meet the GALL Report program element:

Enhancement - Scope of Program. The GALL Report identifies the following criterion for the “scope of program” program element associated with the enhancement:

> Starting with the 1990 addenda to the 1989 edition, the scope of Subsection IWF was revised. The revised percentages are 25% of Class 1 nonexempt piping supports, 15% of Class 2 nonexempt piping supports, 10% of Class 3 nonexempt piping supports, and 100% of supports other than piping supports (Class 1, 2, 3, and MC)........ For multiple components other than piping, within a system of similar design, function, and service, the supports of only one of the multiple components are required to be examined.

Enhancement: The torus vent system supports are to be included within the scope of the ASME Section XI, Subsection IWF Program (see Commitment Item #14).

During the audit, the staff asked the applicant whether the torus vent system supports are the only Class MC supports, and if not, to describe the other Class MC supports. The staff also inquired whether Class MC supports are currently in the scope of IWF.

The applicant stated that the torus vent system supports are the only Class MC supports. In a discussion with the applicant’s technical staff, the staff determined that the torus vent system supports are currently included within the scope of the applicant’s IWE program.

On the basis of its review of the program elements, and discussions with the applicant's technical staff, the staff concluded that those program elements in the ASME Section XI, Subsection IWF Program for which the applicant claims consistency with GALL AMP XI.S3 are consistent with the GALL Report and, therefore, acceptable.

Operating Experience. In the LRA, the applicant stated that the ASME Section XI, Subsection IWF Program is implemented and maintained in accordance with the general requirements for engineering programs. This provides assurance that the programs (1) are effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; (2) have qualified personnel assigned as program managers, with authority and responsibility to implement the program; (3) have adequate resources committed to program activities; and (4) are managed in accordance with plant administrative controls.

The applicant also stated that plant-specific operating experience has identified numerous assessments, performed on both a plant-specific and corporate basis, dealing with program development, effectiveness, and implementation. The ASME Section XI, Subsection IWF Program is continually being upgraded based on industry and plant-specific experience. Additionally, plant operating experience is shared between Progress Energy sites through regular peer group meetings, a common corporate sponsor, and outage participation of program managers from other Progress Energy sites.

Based on discussions with the applicant's technical staff, the staff determined that there are no augmented inspections currently being performed for supports in the scope of the applicant's IWF program. The staff noted that LRA Section 4.7.4 describes a TLAA for the torus vent system supports which stated that there are inaccessible areas associated with non-ASME, Section XI, ISI component supports in the torus (immersed and in vapor environment) that were unable to be coated and are addressed in this analysis. The inaccessible areas of the lower column support for the vent header, located in immersed and vapor zones, were not coated and did not meet the minimum thickness requirement for the 60-year service period. These supports require aging management activities for the 60-year service period. An inspection of the pipe wall thickness of the 6-inch diameter lower column support is required prior to the period of extended operation. The planned inspection method will be a representative volumetric (UT) examination of the wall, with a comparison to the design-basis minimum thickness requirement. Based on results, follow-up actions will be taken, as necessary, including further examinations or replacement of components.

The staff noted that the supports in question will be added to the scope of BSEP AMP B.2.20, ASME Section XI, Subsection IWF Program, prior to the extended period of operation, but that IWF only specifies periodic visual inspection of supports, and inaccessible areas are generally exempted from inspection. Consequently, inspection to IWF requirements will not provide any useful results concerning the remaining wall thickness of the supports.

During the audit, the staff requested that the applicant describe any augmented inspections that may be implemented under the IWF program to provide useful information about the remaining wall thickness of the vent header supports. The applicant stated that the determination of an augmented inspection would be contingent on the results of the TLAA, one-time inspection, and ultrasonic examination of the component. If an unacceptable corrosion rate is detected, an augmented IWF inspection, utilizing an ultrasonic examination, would most likely be created to manage the subject components.

The staff determined that the applicant's approach to assessing the need for augmented inspection under IWF is appropriate and acceptable. On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff found that the applicant has adequately considered operating experience, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.1.20, the applicant provided the UFSAR supplement for the ASME Section XI, Subsection IWF Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's ASME Section XI, Subsection IWF Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Masonry Wall Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.22, "Masonry Wall Program." In the LRA, the applicant stated that this is an existing program that is consistent, with the enhancement, with GALL AMP XI.S5, "Masonry Wall Program."

In the LRA, the applicant stated that this program is based on guidance provided in NRC IE Bulletin 80-11, "Masonry Wall Design," and is implemented through corporate procedure. The program provides for inspections of masonry walls within the scope of license renewal for cracking. Masonry walls within the service water building, reactor building, augmented off-gas building, diesel generator building, control building, and turbine building are within the scope of the Masonry Wall Program. This group includes the masonry walls identified as in proximity to or having attachments to SR components in response to Bulletin 80-11. The program is a condition monitoring program with the inspection frequencies established such that no loss of intended function would occur between inspections.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancement and the associated justifications to determine whether the AMP, with the enhancement, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP's consistency with GALL AMP XI.S5.

In the LRA, the applicant stated the enhancement to this program to meet the GALL Report elements:

Enhancement - Parameters Monitored/Inspected. The GALL Report identifies the following guidance for the "parameters monitored/inspected" program element associated with the enhancement:

> The primary parameter monitored is wall cracking that could potentially invalidate the evaluation basis.

Enhancement: The inspection attribute "cracking" in the program procedure will be revised to remove the restriction on inspecting the walls within 1 foot of wall penetrations or of floor, ceiling, or lateral support connections when assuring the absence of cracks (see Commitment Item #15).

The staff determined that the applicant plans to revise the program procedure by removing the restriction on inspecting the walls within 1 ft of wall penetrations or floor, ceiling, or lateral support connections when assuring the absence of cracks is consistent with the recommendations in the GALL AMP XI.S5.

On the basis of its review of the program elements, and discussions with the applicant's technical staff, the staff concluded that those program elements in the Masonry Wall Program for which the applicant claims consistency with GALL AMP XI.S5 are consistent with the GALL Report and, therefore, acceptable.

Operating Experience. In the LRA, the applicant stated that the Masonry Wall Program has provided for the detection of cracks and other minor aging effects in masonry walls. The corrective action process has ensured the program is implemented consistent with the BSEP design basis. A Licensee Event Report 1-92-012, "Emergency Diesel Generator Building Internal Wall Seismic Support Bolting was Defectively Installed during Plant Construction," required a reevaluation of the original response to Bulletin 80-11. The reevaluation was implemented in strict compliance with Bulletin 80-11 and resulted in a scope expansion from 86 SR masonry walls in the original response to 153 SR walls. Structural monitoring programs are continually being upgraded based upon industry and Progress Energy plant experience. Operating history has shown the Masonry Wall Program to be an effective management tool based on the frequency and acceptable results of past inspections.

The staff asked the applicant how operating experience is captured. The applicant indicated that plant procedure, Operating Experience Program, is used to increase personnel's awareness of plant and industrial operating experience so that lessons learned can be used to adjust its AMP, as necessary. In its procedure, the applicant stated that it provides guidance for using, sharing, and evaluating operating experience at NGG sites as well as promotes the identification and transfer of lessons learned from industry. The staff reviewed the applicant's procedure and determined that the procedure is acceptable.

On the basis of its review of the above operating experience and discussions with the applicant's technical staff, the staff found that the applicant has adequately considered operating experience, consistent with the guidance in the GALL Report.

UFSAR Supplement. In LRA Section A.1.1.22, the applicant provided the UFSAR supplement for the Masonry Wall Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Masonry Wall Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancement and confirmed that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Structures Monitoring Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.23, "Structures Monitoring Program." In the LRA, the applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.S6, "Structures Monitoring Program."

In the LRA, the applicant stated that this program manages the aging effects of civil commodities within the scope of license renewal. The Structures Monitoring Program is implemented, through procedures, in accordance with the regulatory requirements and guidance associated with the MR, 10 CFR 50.65; NRC Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, and NEI (NUMARC) 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2. The applicant also stated that the program incorporates criteria recommended by the INPO Good Practice document 85-033, "Use of System Engineers;" NEI 96-03, "Guidelines for Monitoring the Condition of Structures at Nuclear Plants," and inspection guidance based on industry experience and recommendations from American Concrete Institute (ACI) 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures;" and American Society of Civil Engineers (ASCE) 11-90, "Guideline for Structural Condition Assessment of Existing Buildings." The program consists of periodic inspection and monitoring of the condition of structures and structure component supports to ensure that aging degradation leading to loss of intended functions will be detected and that the extent of degradation can be determined.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the enhancements and the associated justifications to determine whether the AMP, with the enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP elements' consistency with GALL AMP XI.S6.

The staff noted that LRA Appendix B, Table B-1, indicates that GALL AMP XI.S7 is not credited for aging management of water control structures. The staff asked the applicant if the Structures Monitoring Program includes the program elements of GALL AMP XI.S7 to manage aging of water control structures, as specified as an option in the GALL Report, and whether it is completely consistent with GALL AMP XI.S7.

The applicant stated the CLB does not credit RG 1.127. The service water building is managed by the maintenance rule procedure, Condition Monitoring of Structures, which is the primary implementing procedure for the Structures Monitoring Program. The Structures Monitoring Program is credited for the management of all other structures and was found to be effective for management of the service water building, as evidenced by plant operational experience. As such, the service water building was categorized with the generic Note E (Consistent with the GALL Report for material, environment, and aging effect combination, but a different AMP is credited).

As a follow-up to the applicant's initial response, the staff requested that the applicant (1) identify all structures, components, and plant features (e.g., canals) that are essential to maintaining an adequate supply of cooling water for safe shutdown; (2) identify the AMPs that will manage aging for each; and (3) identify how the credited AMP is consistent with the applicable program elements of GALL AMP XI.S7.

The applicant stated that both the intake canal (including sheet-pile cellular bulkhead surrounding the service water intake structure) and the service water intake structure are managed by the Structures Monitoring Program. The intake canal is managed by the Structures Monitoring Program, which specifically includes guidance from RG 1.127 (Reference Attachment 1, sheet 5 of 6, EGR-NGGC- 0351).

The Structures Monitoring Program will be clarified to specify that the inspection interval for the intake canal is not to exceed five years and, based on a comparison, the Structures Monitoring Program effectively envelopes the inspection attributes of RG 1.127, with the exception of inspection frequency, as it relates to the service water intake structure (see Commitment Item #16). The Structures Monitoring Program specifies an inspection frequency commensurate with the safety significance of the structure and its condition, but shall not exceed ten years. RG 1.127 specifies an inspection frequency not to exceed five years. The Structures Monitoring Program will be enhanced to change the inspection frequency for the service water intake structure to not exceed five years (see Commitment Item #16).

As documented in the staff's Audit and Review Report, the applicant has also committed, by letter dated March 14, 2005, to enhance the Structures Monitoring Program to inspect the submerged portions of the service water intake structure at least once every five years (see Commitment Item #16).

Based on the applicant's commitment to inspect the service water intake structure (including submerged portions), intake canal and steel piles at least once every five years, and the staff's comparison of program elements, the staff concluded that the applicant's Structures Monitoring Program includes the necessary program elements of GALL AMP XI.S7 and is acceptable to manage aging of the service water intake structure (including submerged portions), intake canal, and steel piles.

In LRA Section B.2.23, the applicant stated enhancements in meeting the GALL Report element as follows:

Enhancement 1 - Scope of Program The GALL Report recommends the following for the "scope of program" program element associated with the enhancement:

> The applicant specifies the structure/aging effect combinations that are managed by its structures monitoring program.

Enhancement: Administrative controls that implement the program will be revised to: (1) specifically identify the complete list of systems and structures that credit the program for aging management; (2) specifically define the inspection boundaries between the system and associated structure; and (3) notify the responsible engineer when below-grade concrete is exposed (see Commitment Item #16).

The staff asked the applicant to define the commodities, structures, and structural components currently in the scope of the Structures Monitoring Program. The applicant stated that the subject components are identified in LRA Section 3, Table 3.5.2-1 through 15. The staff also noted that the basis document, as documented in the staff's Audit and Review Report, identifies an enhancement to specifically include all systems that credit the program for aging management. The staff reviewed the referenced LRA tables, and concluded that the applicant has identified the commodities, structures, and structural components that credit the Structures Monitoring Program for aging management.

On this basis, the staff determined the applicant's enhancement to scope of program to be acceptable.

Enhancement 2 - Parameters Monitored/Inspected - The GALL Report recommends the following for the "parameters monitored/inspected" program element associated with the enhancement:

> For each structure/aging effect combination, the specific parameters monitored or inspected are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined.

Enhancement: Administrative controls that implement the program will be revised to (1) identify the following commodities within a condition monitoring group - battery racks, damper mounting, doors, electrical enclosures, fire hose stations, instrument supports, instrument racks; (2) include the following inspection attributes - wear (associated with doors), and sedimentation (associated with the intake canal); (3) require the responsible engineer to review the groundwater monitoring results against applicable parameters for determination of an aggressive below-grade environment; (4) require inspection of below-grade concrete when exposed by excavation; (5) specify that an increase in sample size for component supports shall be implemented (rather than should be) commensurate with the degradation mechanisms found, and (6) require an inspection of below-grade concrete, by the responsible engineer, prior to backfill (see Commitment Item #16).

During the audit, the staff reviewed the applicant's references to the Structures Monitoring Program in the AMR results for structures (LRA Section 3.5), and found them to be consistent with the above-listed enhancements to "parameters monitored/inspected."

The staff noted that inspection of below-grade concrete, when exposed by excavation, and periodic monitoring of ground water to ensure that it remains nonaggressive, are the key elements identified in the GALL Report for managing aging of below-grade concrete exposed to groundwater. However, the staff could not determine whether periodic groundwater monitoring is included in the Structures Monitoring Program scope. The listed enhancement only requires review of the results.

The staff requested that the applicant confirm that periodic monitoring of groundwater for aggressiveness will be conducted under the Structures Monitoring Program during the extended period of operation, and also to indicate whether this is currently part of the Structures Monitoring Program, or whether this is an enhancement to the Structures Monitoring Program. If monitoring of groundwater for pH, chlorides, sulfates and phosphates has been previously conducted, the staff requested the applicant to provide the quantitative results and an assessment of the aggressiveness of the groundwater based on comparison of the quantitative results to the recommendation in the GALL Report.

The applicant stated that periodic groundwater monitoring is currently being performed under an implementing procedure, as discussed in the staff’s Audit and Review Report, which will be continued during the period of extended operation. An enhancement to the Structures Monitoring Program implementing procedure will be performed prior to the period of extended operation that requires the structures system engineer to review the groundwater monitoring results against the applicable parameters for determination of an aggressive below grade environment (see Commitment Item #16).

The applicant further stated that groundwater monitoring for pH, chlorides, and sulfates has been performed twice since 2002. The groundwater monitoring for phosphates was performed once and is not part of the groundwater monitoring program. The applicant presented a table, comparing the results against the recommendation in the GALL Report. The measured values for pH, chlorides and sulfates are well within the limits for non-aggressiveness.

The applicant’s one-time inspection performed on well # ESS-3B, to determine a groundwater phosphate level, showed a value of 0.12 ppm. The staff noted that the GALL Report does not identify phosphates as an aggressive groundwater chemical and sets no limits.

The staff noted that the Structures Monitoring Program basis document and the referenced implementing procedure do not specifically define a frequency for periodic groundwater monitoring, to ensure non-aggressiveness. Current groundwater monitoring for other purposes is conducted annually; however, the parameters monitored do not include pH, chlorides, and sulfates as specified in the GALL Report.

The applicant stated that the Structures Monitoring Program will be enhanced to specify an annual frequency for groundwater monitoring to ensure non-aggressiveness. Attachment 8 of the implementing procedure identifies the monitored parameters, which include pH, chlorides and sulfates.

Including the applicant’s additional enhancement to specify an annual frequency for groundwater monitoring, the staff determined that the applicant’s enhancements to “parameters monitored/inspected” are acceptable, on the basis that they are necessary to manage aging of structures and structural components for which the applicant has credited the Structures Monitoring Program.

Enhancement 3 - Detection of Aging Effect. The GALL Report recommends the following for the detection of aging effect program element associated with the enhancement:

> For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific structures monitoring program is to contain sufficient detail on detection to conclude that this program attribute is satisfied.

Enhancement: Revise the system engineer training materials to include the procedure regarding condition monitoring of structures as a procedure requiring In-depth knowledge (see Commitment Item #16).

During the audit the staff determined that this enhancement is acceptable on the basis that improved inspector qualifications will provide additional assurance that aging degradation will be detected and quantified before there is loss of intended functions, as prescribed in the GALL Report.

On the basis of its review of the program elements, and discussions with the applicant's technical staff, the staff concluded that those program elements in the Structures Monitoring Program for which the applicant claims consistency with GALL AMP XI.S6 are consistent with the GALL Report and, therefore, acceptable.

Operating Experience. In the LRA, the applicant stated that the Structures Monitoring Program incorporates best practices recommended by the INPO and inspection guidance based on industry experience and recommendations from ACI and ASCE. A review of inspection reports, self-assessments, and condition reports has concluded the administrative controls are effective in identifying age-related degradation, implementing appropriate corrective actions, and continually upgrading the administrative controls used for structures monitoring. The area surrounding the service water intake structure, adjacent to the intake canal, is subject to an aggressive environment due to high levels of chlorides and sulfates in the intake water. The service water intake structure is monitored on an increased frequency (every two years), due to the environment and history of degradation. The below-grade concrete and concrete below the intake canal water level are monitored from the building interior on a two-year frequency. Exterior concrete exposed to water is monitored annually below the waterline. Groundwater is monitored from various manholes and wells around the site, as well as the intake canal, for pH and the concentration of chlorides and sulfates. This information is provided to the responsible engineer and used to confirm the absence of an aggressive environment in the below-grade areas away from the intake canal.

The applicant's technical staff provided documentation of operating experience-related to concrete degradation of the Units 1 and 2 service water buildings (alternate designation for the service water intake structure). The information provided only covered occurrences of degradation for accessible interior and external concrete surfaces. Degradation was attributed to exposure to aggressive, raw service water. Repairs have been made.

During the review and audit, the staff requested the applicant to provide a summary of operating experience for submerged regions of the Units 1 and 2 service water buildings and for the intake canal and sheet piles.

The applicant stated that operating experience for the submerged portions of the service water intake structure is obtained from divers performing annual preventive maintenance. The only degradation observed was a minor spall of the concrete. No rebar was exposed and an evaluation determined the damage to be cosmetic. No repairs were required. The intake canal is monitored more frequently, with the depth studies typically conducted once per quarter and dredging typically conducted annually. Plant operating history has identified an issue with sedimentation buildup in front of the circulating traveling screens, which is managed by depth measurements and dredging.

The applicant also stated that thickness measurements have been performed on the sheet-pile bulkhead and the results found the area below the barnacle line is essentially the original design thickness. Minor thickness losses were identified above the barnacle line, but were not determined to have an impact on the structural integrity of the bulkhead. The area surrounding a diesel generator jacket water exhaust line penetration (approximately 8 feet above the barnacle line) was found to be 10 to 20 percent of the original design thickness with several through-walls. This degradation was originally identified by a maintenance rule structural inspection in 2002 and work orders were created to perform ultrasonic measurements of the degraded areas. The results of the ultrasonic measurements are currently being evaluated for potential repair options.

The staff asked the applicant whether the annual preventive maintenance for the submerged portions of the service water intake structure and the intake canal quarterly depth studies and annual dredging are credited by and/or included in the Structures Monitoring Program.

The applicant stated that the Structures Monitoring Program will be enhanced to include inspections of the submerged portions of the service water intake structure on a frequency commensurate with RG 1.127, not to exceed five years; and (2) the majority of the intake canal volume is utilized by the circulating water system, which is not a license renewal system and is not required for safe shutdown. Monitoring of the intake canal on a quarterly frequency and annual dredging is primarily associated with operation of the circulating water system. The Structures Monitoring Program does credit the intake canal depth studies; however, dredging is based on the results of the depth studies and is not tied to any specific frequency. The implementing procedure for the intake canal depth studies recommends quarterly performance; however, the inspections may be deferred at the discretion of the E&RC supervisor based on operating experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the staff concludes that the applicant’s Structures Monitoring Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA A.1.1.23, the applicant provided the UFSAR supplement for the Structures Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Structures Monitoring Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.24, "Protective Coating Monitoring and Maintenance Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exception and enhancements, with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program."

In the LRA, the applicant stated that the Protective Coating Monitoring and Maintenance Program is a condition monitoring program for Service Level I coatings applied inside the primary containment (drywell and torus) of Units 1 and 2. Coating parameters monitored include blistering, cracking, flaking, rusting, and other distress (indicated by peeling, undercutting, discoloration or physical damage). The program prevents clogging of ECCS suction strainers and containment spray nozzles by assuring that the quantity of damaged or degraded coatings inside primary containment that could detach during a loss-of-coolant accident remains within analyzed limits. The limits are based upon head loss calculations for ECCS suction strainers installed in the mid-1990s that quantify the amount of debris of various types, including insulation, corrosion products, and coating debris that can be tolerated without impairing system function. Specific limits apply for coating debris.

The program also performs in-process inspections for coating repairs and refurbishments to assure coatings are qualified. Unqualified coatings and damaged or degraded coatings are quantified and tracked on a coatings exempt log, and the cumulative total is compared to qualified limits.

Staff Evaluation. During its audit, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and enhancements and the associated justifications to determine whether the AMP, with the exception and enhancements, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff's BSEP Audit and Review Report, which provide an assessment of the AMP elements' consistency with GALL AMP XI.S8.

As documented in the Audit and Review Report, the applicant stated that its Protective Coating Monitoring and Maintenance Program is based on a commitment to meet the requirements of Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Controlled Nuclear Power Plants," Revision 0, issued June 1973 (see Commitment Item #17). The GALL Report states that a comparable program for monitoring and maintaining protective coatings inside containment, developed in accordance with RG 1.54, Revision 0, is also acceptable as an AMP for license renewal. Therefore, the staff determined that the applicant's Protective Coating Monitoring and Maintenance Program was developed in accordance with a regulatory guide that is acceptable to the staff.

During refueling outages, the program performs inspections to determine if any existing qualified coatings were damaged or degraded during the previous operating cycle and provides for disposition of the damage. The program also performs in-process inspections for any Service Level I coatings applied during the refueling outage, and provides for the disposition of any unacceptable coatings. Disposition options include removal of discrepant coatings, repair or recoating, or entry on the coating exempt log for the applicable BSEP unit. The applicant updates the coating exempt logs during refueling outages by deleting any previously identified unqualified coatings that were removed, and adding any newly discovered unqualified coatings. The applicant performs engineering evaluations for the newly discovered unqualified coatings The coating exempt logs and engineering evaluations are maintained as quality assurance records.

The applicant monitors and controls the sludge, dirt, dust, rust, qualified paints, unqualified paints, and miscellaneous materials that could clog the ECCS suction strainers and containment spray nozzles. The staff noted that the Protective Coating Monitoring and Maintenance Program is used to manage the aging effects related to clogging the ECCS strainers; however, it only addresses the mass of qualified paints that could become debris.

During the audit, the staff asked the applicant what other programs are credited for other types of debris. As documented in the Audit and Review Report, the applicant responded that the Preventive Maintenance Program will be used to manage the amount of sludge, dirt/dust, rust, and other miscellaneous debris in the torus. The staff reviewed the applicant's response and determined that the applicant has identified those AMPs that manage aging effects that may contribute to the debris inside the primary containment.

In the LRA Section B.2.24, the applicant stated the following exception to the GALL Report elements.

<u>Exception - Preventive Actions and Operating Experience</u> The GALL Report identifies the following guidance for the program elements associated with the exception taken:

> <u>Preventive Action</u>: With respect to loss of material due to corrosion of carbon steel elements, this program is a preventive action.
>
> <u>Operating Experience</u>: NRC Generic Letter 98-04 describes industry experience pertaining to coatings degradation inside containment and the consequential clogging of

sump strainers. RG 1.54, Rev. 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 is expected to be an effective program for managing degradation of Service Level I coatings, and consequently an effective means to manage loss of material due to corrosion of carbon steel structural elements inside containment.

Exception: The Protective Coating Monitoring and Maintenance Program is not credited within the license renewal review for prevention of corrosion of carbon steel.

The staff reviewed the associated AMRs in the LRA. The containment sump strainers are the only components in the plant that credit the Protective Coating Monitoring and Maintenance Program as an AMP. The degradation of the carbon steel components, which have applied coatings, is managed by other AMPs, such as the Water Chemistry, ASME Section XI Inservice Inspections, One-Time Inspection, System Monitoring, Preventive Maintenance, Above-Ground Steel Tanks, and Open-Cycle Cooling Water System Programs. The staff determined that not crediting the Protective Coating Monitoring and Maintenance Program for prevention of corrosion of carbon steel components is acceptable, since the aging of the affected components is being monitored by other staff-approved AMPs.

On the basis of its review of the above exception, and discussions with the applicant's technical staff, the staff concluded that the exception stated by the applicant for the Protective Coating Monitoring and Maintenance Program to the program elements for AMP XI.S8 in the GALL Report is acceptable.

In the BSEP LRA, the applicant stated that the following enhancements will be implemented prior to the period of operations to meet the GALL Report elements.

Enhancement 1 - Detection of Aging Effects. The GALL Report identifies the following guidance for the "detection of aging effects" program element associated with the enhancement:

> American Society for Testing and Material (ASTM) D 5163-96, paragraph 5, defines the inspection frequency to be each refueling outage or during other major maintenance outages as needed. ASTM D 5163-96, paragraph 8, discusses the qualifications for inspection personnel, the inspection coordinator and the inspection results evaluator. ASTM D 5163-96, subparagraph 9.1, discusses development of the inspection plan and the inspection methods to be used. It states, "A general visual inspection shall be conducted on all readily accessible coated surfaces during a walk-through. After a walk-through, thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through. A thorough visual inspection shall also be carried out on all coatings near sumps or screens associated with the emergency core cooling system (ECCS)." This subparagraph also addresses field documentation of inspection results. ASTM D 5163-96, subparagraph 9.5, identifies instruments and equipment needed for inspection.

Enhancement: Program administrative controls will be enhanced to: (a) add a requirement for a walk-through, general inspection of containment areas during each refueling outage, including all accessible pressure-boundary coatings not inspected under the ASME Section XI, Subsection IWE Program; (b) add a requirement for a detailed, focused inspection of areas noted as deficient during the general inspection; and, (c) assure that the qualification requirements for persons evaluating coatings are consistent among the Service Level I coating specifications, inspection procedures, and application procedures, and meet the requirements of ANSI N101.4, “Quality Assurance for Protective Coatings Applied to Nuclear Facilities “(see Commitment Item #17).

Enhancement (1a) fulfills the GALL Report’s guidance in that the inspection frequency will be every refueling outage. Enhancement (1b) fulfills the GALL Report’s guidance that thorough visual inspections shall be carried out on areas noted as deficient during the walk-through. Enhancement (1c) fulfills the GALL Report’s expectation that qualification requirements will be met for inspection personnel, the inspection coordinator, and the inspection results evaluator. The staff determined that these enhancements are consistent with the guidance provided in the GALL AMP XI.S.8. On the basis of its audit of the Protective Coating Monitoring and Maintenance Program and the associated GALL AMP, the staff determined that this enhancement is acceptable.

<u>Enhancement 2 - Acceptance Criteria</u>. The GALL Report identifies the following evaluation and technical basis for the “acceptance criteria” program element associated with this enhancement.

> ASTM D 5163-96, subparagraphs 9.2.1 through 9.2.6, 9.3 and 9.4, contain guidance for characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are identified for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delaminating, and rusting. ASTM D 5163-96, paragraph 11, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Repair work is prioritized as major or minor defective areas. A recommended corrective action plan is required for major defective areas, so that these areas can be repaired during the same outage, if appropriate.

<u>Enhancement</u>: Program administrative controls will be enhanced to document the results of inspections and compare the results to previous inspection results and to acceptance criteria. These activities are performed, but are not adequately incorporated into program procedures (see Commitment Item #17).

The enhancement of program administrative controls fulfills the GALL Report’s expectation that inspection reports will be evaluated by the responsible evaluation personnel, who will prepare a summary of findings and recommend corrective actions, when required. The staff determined that the enhanced administrative controls will formalize current activities by requiring inspection results to be reviewed by the appropriate system engineer, who verifies that inspection findings meet acceptance criteria, and trends the inspection results in the PassPort database. On the basis of its audit of the Protective Coating Monitoring and Maintenance Program, the staff determined this enhancement to be acceptable as such changes to the applicant’s program will provide additional assurance that the effects of aging will be adequately managed.

On the basis of its review of the above enhancements, and discussions with the applicant's technical the Protective Coating Monitoring and Maintenance Program AMP B.2.24 to make it consistent with the program elements for GALL AMP XI.S8 are acceptable.

Operating Experience. In the LRA, the applicant stated that the applicant's response to GL 98-04 described how the Protective Coating Monitoring and Maintenance Program complies with RG 1.54, Revision 0, which endorses ANSI N101.4-1972. The response described the program attributes, including design and licensing basis, procurement, control of coating application, quality assurance, monitoring, and maintenance of Service Level 1 coatings. It also explained that the protective coatings below the waterline in the torus of each unit were removed and replaced from 1994 to 1996. The replacement coatings were applied using materials, application methods, and quality assurance practices conforming to the requirements of ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," ANSI N101.2-1972, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," and ANSI N512-1974, "Protective Coatings (Paints) for the Nuclear Industry."

The applicant also stated that Service Level I protective coatings were determined to be within the scope of 10 CFR 50.65, the MR; and an MR monitoring system was created to manage ECCS suction strainer debris. Protective coatings are managed as a discrete subset of this maintenance rule debris management system. During refueling outages, inspections are performed to identify qualified coatings that were damaged or degraded during the previous operating cycle.

As documented in the Audit and Review Report, the applicant stated that BSEP installed larger ECCS strainers in the mid-1990s and prepared a detailed pump head loss calculation to determine acceptable ECCS strainer debris loading limits used in the program. Service Level 1 protective coatings are managed as a discrete subset of this maintenance rule debris management system. BSEP performed baseline inspections of Unit 1 and 2 containments. Unqualified and damaged coatings that were not removed at that time were logged on a coatings exempt log established for each unit. Engineering evaluations were performed to compare the cumulative total to the MR and design limits.

The applicant identified an increasing trend in the quantity of unqualified coatings remaining inside primary containment during the last outages for each unit. As a result, the applicant developed an integrated plan to address the removal of unqualified coatings inside the drywell and torus. While the quantity of unqualified coatings present is less than the applicable limits, this initiative is intended to further reduce the quantity of unqualified or degraded coatings remaining in place inside primary containment.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the staff concludes that the Protective Coating Monitoring and Maintenance Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.24, the applicant provided the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s Protective Coating Monitoring and Maintenance Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.26, “Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program.” In the LRA, the applicant stated that this is a new program that is consistent, with exception, with GALL AMP XI.E2, “Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.”

In the LRA, the applicant stated that this program is credited for aging management of radiation monitoring and neutron flux monitoring instrumentation cables not included in the BSEP EQ Program. Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance (IR). For circuits with a sensitive, high-voltage, low-level signal, such as radiation monitoring and nuclear instrumentation circuits, a reduction in IR is a concern because it may contribute to signal inaccuracies. For radiation monitoring instrumentation circuits, the results of routine calibration tests will be used to identify the potential existence of cable aging degradation. For neutron flux instrumentation circuits, field cables will be tested at least once every 10 years (see Commitment Item #19). Testing may include IR tests, time domain reflectometry (TDR) tests, current-versus-voltage (I/V) testing, or other testing judged to be effective in determining cable insulation condition.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and the associated justifications to determine whether the AMP, with the exception, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provide an assessment of the AMP elements' consistency with GALL AMP XI.E2 and BSEP plant procedure, CAP-NGGC-0202, “Operating Experience Program,” Revision 8.

In its basis documentation, as documented in the Audit and Review Report, the applicant stated that the “parameters monitored/inspected,” “detection of aging effects,” and “acceptance criteria” program elements are not consistent with GALL XI.E2, but are consistent with the staff's proposed ISG-15, Revision of GALL AMP XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environment Qualification Requirement Used in Instrumentation Circuits."

During the audit, the staff noted that the basis documentation for the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (1) did not require a review of calibration or surveillance results for indication of cable degradation, as recommended by ISG-15; (2) was not clear as to whether or not cable testing included the cable connections; and (3) did not provide a basis for the10-year testing frequency for the neutron flux monitoring instrumentation circuits cable systems.

In response to staff questions, as documented in the Audit and Review Report, the applicant stated that it will revise the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program basis documentation and the LRA accordingly as follows:

> AMP B.2.26 will be revised to include a review of calibration or surveillance results for indication of cable degradation consistent with NRC Interim Staff Guidance (ISG)-15, Revision to Generic Aging Lessons Learned (GALL) Aging Management Program XI.E2. The first reviews will be completed before the end of the initial 40--year license term and at least once every 10 years thereafter
>
> Cable testing includes the entire cable system which includes cable connections, and state that the test frequency of the Neutron Monitoring System cable systems shall be determined based on engineering evaluation not to exceed ten years. The first test shall be completed prior to the end of the initial 40-year license term.

The staff reviewed the applicant's responses and, on the basis that these changes are consistent with ISG-15, the staff determined that the applicant's responses are acceptable.

In the LRA, the applicant stated the following exception to the program elements in the GALL Report:

The GALL Report identifies the following recommendation for "parameters monitored/inspected," "detection of aging effects," and "acceptance criteria" program elements associated with the exception taken:

> Parameters Monitored/Inspected. The parameters monitored are determined from the plant technical specifications and are specific to the instrumentation loop being calibrated, as documented in the surveillance testing procedure.
>
> Detection of Aging Effects. Calibration provides sufficient indication of the need for corrective actions by monitoring key parameters and providing trending data based on acceptance criteria related to instrumentation loop performance. The normal calibration frequency specified in the plant technical specifications provides reasonable assurance that severe aging degradation will be detected prior to loss of the cable intended function. The first tests for license renewal are to be completed before the period of extended operation.

> Acceptance Criteria. Calibration readings are to be within the loop-specific acceptance criteria, as set out in the plant technical specifications surveillance test procedures.

Exception: Direct cable testing will be performed as an alternative to instrument loop calibrations for neutron flux monitoring instrumentation circuits

In the LRA, the applicant stated that direct cable testing will be performed as an alternative to instrument loop calibrations for neutron flux monitoring instrumentation circuits. The staff reviewed the applicant's exception and determined that the exception is acceptable since it is consistent with the guidance in ISG-15, which states that either calibration results or findings of surveillance testing or direct testing of cable systems can be used to detect electrical cable aging degradation associated with the electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits.

On the basis of its review of the above exception, the staff concluded that the exception stated by the applicant for the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program to the program elements for GALL AMP XI.E2 is acceptable.

Operating Experience. In the LRA, the applicant stated that the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program is a new program with no Operating experience history. However, as noted in the GALL Report, industry Operating experience has shown that exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced IR. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation circuits, since it may contribute to signal inaccuracies.

The staff asked the applicant how operating experience is captured. The applicant indicated that a plant procedure, as documented in the Audit and Review Report, is used to train and increase personnel's awareness of plant and industrial operating experience so that lessons learned can be used to adjust its AMP, as necessary. In its procedure, the applicant stated that it provides guidance for using, sharing, and evaluating Operating experience at NGG sites and promotes the identification and transfer of lessons learned from industry. The staff reviewed the applicant's procedure and determined that the procedure is acceptable.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the staff concludes that the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.26, the applicant provided the UFSAR supplement for the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program, which states:

> The electrical cables not subject to 10 CFR 50.49 Environmental Qualification requirements used in instrumentation circuits program is credited for the aging management of radiation monitoring and neutron flux monitoring instrumentation cables

> not included in the BSEP EQ program. Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance (IR). A reduction in IR is a concern for circuits with sensitive, low-level signals, such as radiation monitoring and nuclear instrumentation circuits, since it may contribute to signal inaccuracies. For radiation monitoring instrumentation circuits, the results of routine calibration tests will be used to identify the potential existence of cable aging degradation. For neutron flux instrumentation circuits, field cables will be tested at least once every 10 years. Testing may include IR tests, time domain reflectometry (TDR) tests, current versus voltage (I/V) testing, or other testing judged to be effective in determining cable insulation condition. This program is consistent with the corresponding program described in NUREG-1801, with the exception that it allows direct cable testing for neutron flux monitoring circuits.

As documented in the Audit and Review Report, the applicant provided the following revised UFSAR supplement as part of its response to Question B.2.26-1:

> The Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program is credited for the aging management of radiation monitoring and neutron flux monitoring instrumentation cables not included in the BSEP EQ Program. Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance (IR). A reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation circuits since it may contribute to signal inaccuracies. For radiation monitoring instrumentation circuits, the review of calibration results or findings of surveillance testing will be used to identify the potential existence of cable system aging degradation. This review will be performed at least once every 10 years and the first review will be completed before the end of the current license term. Cable systems used in neutron flux instrumentation circuits will be tested at a frequency not to exceed 10 years based on engineering evaluation, and the first testing will be completed before the end of the current license term. Testing may include IR tests, time domain reflectometry (TDR) tests, current versus voltage (I/V) testing, or other testing judged to be effective in determining cable system insulation condition. This Program is consistent with the corresponding program described in NUREG-1801, as modified by NRC Interim Staff Guidance Issue No. 15, with the exception that it allows direct cable testing of neutron monitoring cable systems.

On the basis of its review of the revised UFSAR supplement for this program, the staff determined that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications, and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for

this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.20 Reactor Coolant Pressure Boundary Fatigue Monitoring Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.3.1, “Reactor Coolant Pressure Boundary Fatigue Monitoring Program.” In the LRA, the applicant stated that this is an existing program that is consistent, with exception and enhancements, with GALL AMP X.M1, “Metal Fatigue of Reactor Coolant Pressure Boundary.”

In the LRA, the applicant stated that this program includes preventive measures to mitigate fatigue cracking caused by anticipated cyclic strains in metal components of the reactor coolant pressure boundary. This is accomplished by monitoring and tracking the significant thermal and pressure transients for limiting reactor coolant pressure boundary components in order to prevent the fatigue design-limit from being exceeded. Also, the applicant stated that this program addresses the effects of the reactor coolant environment on component fatigue life by including, within the “scope of program” program element, environmental fatigue evaluations of the sample locations specified in NUREG/CR-6260, “Application of NUREG/CR-5999, Interim Fatigue Curves to Selected Nuclear Power Plant Components,” for older-vintage BWRs. These locations were evaluated by applying environmental correction factors to ASME Section III, Class 1 fatigue analyses, as specified in NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” for carbon and low-alloy steel; NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” for stainless steel; and methodology from Argonne National Laboratory for nickel-based alloys. Prior to exceeding the design limit, preventive and/or corrective actions are triggered by this program.

Staff Evaluation. During its audit, the staff confirmed the applicant’s claim of consistency with the GALL Report. Details of the staff’s audit evaluation of this AMP are documented in the BSEP Audit and Review Report. The staff reviewed the exception and enhancements and the associated justifications to determine whether the AMP, with the exception and enhancement, remains adequate to manage the aging effects for which it is credited.

The staff interviewed the applicant's technical staff and reviewed the applicable documents in the staff’s BSEP Audit and Review Report, which provide an assessment of the AMP elements' consistency with GALL AMP X.M1.

In LRA Section B.3.1, the applicant stated an exception to GALL AMP X.M1 program elements, as follows:

Exception - Monitoring and Trending. The GALL Report recommends the following for the “monitoring and trending” program element associated with the exception taken:

> The program monitors a sample of high fatigue usage locations. As a minimum, this sample is to include the locations identified in NUREG/CR 6260

Exception: The limiting locations selected for monitoring will be those with a 60-year CUF value (including environmental effects, where applicable) of 0.5 or greater. The monitoring sample may not include all locations identified in NUREG/CR-6260 that are within the scope of the program if they do not meet this criterion.

The staff considered the applicant's exception to be inconsistent with the GALL Report and requested that the applicant to clarify why all of the locations identified in NUREG/CR 6260 would not be included.

As documented in the Audit and Review Report, the applicant provided the following response:

> The BNP Fatigue Monitoring Program will be enhanced to monitor fatigue for each of the six locations from NUREG/CR-6260 applicable to the older-vintage General Electric plants, considering reactor water environmental effects. There will no longer be an exception to GALL Program Element 5-1 for Monitoring and Trending.

During the audit the staff reviewed this response and determined that the applicant's removal of this exception to the GALL Report is acceptable because BSEP will include all locations that meet the original criteria and the six locations identified in NUREG/CR-6260. The applicant's revision to the Reactor Coolant Pressure Boundary Fatigue Monitoring Program, removing the original exception, will result in more locations being monitored by the program. The applicant has retained its 0.5 CUF criteria, but it does not apply to the six locations which will be included regardless of the predicted CUF.

In LRA Section B.3.1, the applicant stated the following enhancements to meet the program elements for AMP XI.M1 in the GALL Report:

Enhancement 1 - Scope of Program. The GALL Report recommends the following criterion for the "scope of program" program element associated with the enhancement:

> The program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.

Enhancement: Expand the scope of the current fatigue monitoring program to include the reactor coolant pressure boundary components beyond the Reactor Pressure Vessel (RPV), including the NUREG/CR-6260 locations outside the RPV (see Commitment Item #21).

The staff determined that the applicant's enhancement to the "scope of program" program element is necessary to ensure consistency with the GALL Report, and is acceptable.

Enhancement 2 - Preventive Actions. The GALL Report recommends the following criterion for the "preventive actions" program element associated with the enhancement:

> Maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of reactor coolant system components due to anticipated cyclic strains.

Enhancement: Enhance the administrative controls of the Reactor Coolant Pressure Boundary Fatigue Monitoring Program to address preventive actions if an analyzed component is determined to be approaching the design limit, including an option to consider operational changes to reduce the number or severity of future transients affecting the component (see Commitment Item #21).

The staff determined that operational changes to reduce the number or severity of future transients affecting the component, if feasible, is one acceptable way for maintaining the fatigue usage factor below the design Code limit. The staff found this enhancement to be acceptable, as such changes to the applicant's program will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3 - Monitoring and Trending. The GALL Report recommends the following recommendations for the "monitoring and trending" program element associated with the enhancement:

> The program monitors a sample of high fatigue usage locations. As a minimum, this sample is to include the locations identified in NUREG/CR-6260.

Enhancement: Include a requirement in the administrative controls of the Reactor Coolant Pressure Boundary Fatigue Monitoring Program to reassess the limiting locations that are monitored, considering the analyses for RCPB locations that were added to the program scope. Specify the selection criterion to be locations with a 60-year CUF value (including environmental effects where applicable) of 0.5 or greater.

The staff reviewed and determined that the 0.5 CUF selection criterion is acceptable for specifying additional sample locations, on the basis that it provides a margin to ensure that the applicant's program will include all locations having the potential to exceed 1.0 CUF at 60 years (see Commitment Item #21).

The staff found this enhancement to be acceptable as such changes to the Reactor Coolant Pressure Boundary Fatigue Monitoring Program will provide additional assurance that the effects of aging will be adequately managed.

Operating Experience. In the LRA, the applicant stated that a review was conducted of NRC INs, Bulletins, and GLs for the years 2000 through 2004, but no applicable Operating experience items were identified that relate to fatigue monitoring or to exceeding fatigue design-limits. The existing program has been effective in assuring that the fatigue analyses for the RPV components remain below the design limit of 1.0; the highest CUF value as of March 2001, was 0.354 (for the refueling bellows support), and the highest 40-year projected fatigue usage value was 0.53 (also for the refueling bellows support).

The staff asked whether a manual or automated methodology is used to calculate and update the CUF. In its response, the applicant stated that the current program utilizes a combination of interim CUF updates after each fuel cycle, along with a comprehensive fatigue usage analysis performed periodically, typically every 10 years. Both the interim updates and comprehensive fatigue usage analysis are performed manually. However, the comprehensive fatigue usage analysis is performed using the Fatigue-Pro Cycle Evaluation Module (CEM) to assess the impact of actual transient occurrences on the fatigue of limiting components. The Fatigue-Pro CEM method uses temperature and pressure data obtained from actual plant operations to determine the stresses resulting from operational transients. The transient data are supplied to the Fatigue-Pro CEM program manually.

The staff asked when the existing program was first implemented, whether any locations had been added or deleted, and which locations are currently monitored. The applicant stated that the current program, utilizing a combination of interim CUF updates and a comprehensive fatigue usage analysis, was implemented in the early 1990s. Over the life of the BSEP units, locations have been added and deleted, as documented in LRA Table 4.3-2. The locations currently monitored are the refueling bellows support, reactor vessel head closure studs, recirculation inlet nozzles, core spray nozzles, and feedwater nozzles.

The staff asked how starting CUFs were calculated when the program was first implemented, and how starting CUFs will be calculated for locations to be added to the program scope. The applicant stated that, as discussed in LRA Section 4.3.1, the original fatigue analyses were prepared in accordance with the ASME Code, Section III, 1965 Edition, with Addenda through Summer 1967, for Class A vessels. The fatigue analysis of the vessel flange was performed using the 1968 Edition of the Code. By 1981, the actual number of startup-shutdown cycles began to approach the number postulated in the design analyses, which required further evaluation. To address this issue, a fatigue usage update was performed for both units by General Electric (GE) in 1983. The GE evaluation determined that analysis of the five most limiting locations would bound the fatigue for the remaining components due to the relatively low design-fatigue usage values for the remaining components. The analyzed locations included the RPV head closure studs, recirculation inlet nozzles, core spray nozzles, Unit 1 feedwater nozzle, and refueling bellows support.

The applicant further stated that when the current program, utilizing a combination of interim CUF updates and a comprehensive fatigue usage analysis, was implemented; the plant cyclic data that characterized plant operations from original plant startup through 1992 were used as inputs to the Fatigue-Pro CEM program, and the fatigue usage to date for each component was computed. Regarding additional components to be added to the scope of the program as a result of reactor coolant environmental effects, LRA Section 4.3.3 provides a summary of the CUF analyses for these components.

The staff asked whether the CUFs (including environmental effects) have already been projected to the end of the extended period of operation for the locations identified in NUREG/CR-6260, and, if already calculated, to identify the locations that will not be included in the program scope, based on the CUF greater-than-0.5 criterion. The applicant stated that, for each location identified in NUREG/CR-6260, CUF values have been projected to the end of the period of extended operation, including consideration of environmental effects, as shown in LRA Tables 4.3-3 and 4.3-4. Each of the locations identified in NUREG/CR-6260 will be included in the cycle evaluation module and will not be deleted based upon the CUF greater-than-0.5 criterion.

The staff reviewed the applicant’s responses and concluded that the existing Reactor Coolant Pressure Boundary Fatigue Monitoring Program has been implemented in accordance with accepted technical practice for fatigue monitoring.

The staff reviewed the operating experience provided in the LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the staff concludes that the Reactor Coolant Pressure Boundary Fatigue Monitoring Program will adequately manage the aging effects that are identified in LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.1.28, the applicant provided the UFSAR supplement for the Reactor Coolant Pressure Boundary Fatigue Monitoring Program (see Commitment Item #21).

As documented in the Audit and Review Report, as part of its response to a staff question, the applicant revised the UFSAR supplement to reflect its new commitment to include all sample locations specified in NUREG/CR-6260, independent of the 0.5 CUF selection criterion. The revised UFSAR supplement states that:

> The Reactor Coolant Pressure Boundary (RCPB) Fatigue Monitoring Program includes preventive measures to mitigate fatigue cracking caused by anticipated cyclic strains in metal components of the reactor coolant pressure boundary. This is accomplished by monitoring and tracking the significant thermal and pressure transients for limiting reactor coolant pressure boundary components in order to prevent the fatigue design limit from being exceeded. The Program addresses the effects of the reactor coolant environment on component fatigue life by including, within the Program scope, environmental fatigue evaluations of the sample locations specified in NUREG/CR-6260, "Application of NUREG/CR-5999, Interim Fatigue Curves to Selected Nuclear Power Plant Components," for older-vintage BWRs. This Program is consistent with the corresponding Program described in NUREG-1801.
>
> Prior to the period of extended operation, the program will be enhanced to: (1) expand the Program scope to include an evaluation of each reactor coolant pressure boundary component included in NUREG/CR-6260, (2) provide preventive action requirements including requirement for trending and consideration of operational changes to reduce the number or severity of transients affecting a component, (3) include a requirement to reassess the locations that are monitored considering the RCPB locations that were added to the Program scope, (4) specify the selection criterion to be locations with a 60-year CUF value (including environmental effects where applicable) of 0.5 or greater, other than those identified in NUREG/CR-6260, (5) address corrective actions for components approaching limits, with options to include a revised fatigue analysis, repair or replacement of the component, or in-service inspection of the component (with prior NRC approval), and (6) address criteria for increasing sample size for monitoring if a limiting location is determined to be approaching the design limit.

The staff reviewed the revised UFSAR supplement for this section and determined that the information provided in the revised UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant’s Reactor Coolant Pressure Boundary Fatigue Monitoring Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL

Report. In addition, the staff reviewed the exception and the associated justifications, and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the staff has reviewed the enhancements and confirmed that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 Summary of Conclusions for AMPs That Are Consistent With the GALL Report with Exceptions or Enhancements

On the basis of its audit of the applicant's programs, the staff determined that those portions of the program for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the related exceptions and enhancements to meet the GALL Report programs, and determined that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

On the basis of its review of the UFSAR supplement for these programs, the staff concluded that it provides an adequate summary description of the programs, as required by 10 CFR 54.21(d).

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified that the following AMPs were plant-specific:

For AMPs that are not consistent with or not addressed by the GALL Report, the staff performed a complete review of the AMPs to determine if they were adequate to monitor or manage aging. The staff’s review of these plant-specific AMPs is documented in the following sections of this SER.

- Reactor Vessel and Internals Structural Integrity Program
- Systems Monitoring Program
- Preventive Maintenance Program
- Phase Bus Aging Management Program
- Fuel Pool Girder Tendon Inspection Program

3.0.3.3.1 Reactor Vessel and Internals Structural Integrity Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.28, “Reactor Vessel and Internals Structural Integrity Program.” In the LRA, the applicant stated that this is an existing, plant-specific program.The applicant identified this program as a plant-specific AMP that incorporates both the required inservice inspection activities for Units 1 and 2 RV and RV internal components, as implemented in accordance of the applicant's ASME Section XI, Subsections IWB, IWC, and IWD Program, and the recommended inspection and flaw evaluation activities of the BWRVIP.

As a plant-specific AMP, the RV&ISIP includes a discussion on how the program meets the ten program elements required for AMPs, as defined and discussed in Branch Position RLSB-1 of SRP-LR, Appendix A, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." The staff lists and evaluates the applicant's program elements for the RV&ISIP in the "Technical Evaluation" subsection.

The RV&ISIP also includes 10 tables which discuss how the applicant's AMP conforms to or deviates from the recommendations in pertinent BWRVIP inspection and flaw evaluation guidelines and pertinent NRC Applicant Action Items (AAIs) issued on these BWRVIP documents. The staff listed and evaluated the applicant's responses to the AAIs in the "Technical Evaluation" subsection.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B,2,28, regarding the applicant's demonstration of the RV&ISIP to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.The applicant stated that the RV&ISIP is an existing plant-specific AMP. Therefore, the applicant described the capabilities of this AMP in terms of how the program conforms to the 10 program elements for AMPs recommended in Branch Position RLSB-1 of the SRP-LR. Of these program elements, the staff evaluates the "corrective actions," "confirmation process," and "administrative controls" program elements for the RV&ISIP as part of the staff's evaluation of the applicant's Quality Assurance Program. The staff's evaluation of the Quality Assurance Program is given in SER Section 3.0.4. The staff's evaluation of the remaining seven program elements for the RV&ISIP are given in subsections (1) through (7) below. In addition, subsection (8) to the staff evaluation for this AMP provides the staff's assessment of the applicant's responses to NRC applicant action items (AAIs) on applicable Topical Reports that were issued by Boiling Water Reactor Vessel and Internals Project (BWRVIP) for operating U.S. BWRs and that are within the scope of the RV&ISIP.

(1) Scope of Program

The applicant stated that the scope of the RV&ISIP is used to manage the effects of cracking, loss of material, flow blockage, loss of preload, and reduction in fracture toughness of the Units 1 and 2 RV and RV internal components. The applicant stated that EPRI Topical Report No. TR-113596, "BWRVIP-74-A: BWRVIP Vessel and Internals Project BWR Reactor Vessel Inspection and Flaw Evaluation Guidelines for License Renewal" (BWRVIP-74-A), dated June 2003, is the basis for the RV&ISIP. The applicant also stated that implementation of the guidelines in BWRVIP-74-A is performed in accordance with the implementation guidelines established in BWRVIP-94.

LRA Table 3.1.2-1 credits the RV&ISIP with aging management for the following RV and RV internal components:

- vessel shell attachment welds
- feedwater nozzles and their thermal sleeves

- vessel instrumentation penetrations
- standby liquid control penetrations
- flux monitor penetrations
- RV drain line penetration
- low pressure core spray line thermal sleeves
- core shroud shell (including upper, middle, and lower shell components)
- core shroud access hole covers
- core shroud repair hardware
- core plates and their bolts
- core plate plugs
- core shroud support structure
- top guide
- core spray line headers, nozzles, spargers, and spray-rings
- core spray line nozzle thermal
- jet pump instrument penetrations
- jet pump assembly components, including thermal sleeves, inlet headers, riser brace arms, hold down beams, inlet elbows, mixing assemblies, diffusers, castings, sensing lines, and fastener components (holdown beam keeper, lock plate, and bolts)
- fuel support and control rod drive (CRD) assembly components, including orifice fuel support and CRD housings
- flux monitor dry tubes, including those for the source range monitors, intermediate range monitors
- steam dryers (non-safety)
- shroud head and separators (non-safety)
- feedwater spargers (non-safety)
- RV surveillance capsule holder (non-safety)

BWRVIP-74-A provides recommended guidelines for inspection, assessment, mitigation, and repair/replacement strategies for the RV and RV internal components. The BWRVIP submitted BWRVIP-74 for NRC review and approval on September 19, 1999, and supplemented the report with additional information on March 7, 2000. The staff's approved BWRVIP-74 in an NRC letter and FSER, "Acceptance for Referencing EPRI Proprietary Report TR-113596, 'BWRVIP Vessel and Internals Project BWR Reactor Vessel Inspection and Flaw Evaluation Guidelines (BWRVIP-74)' and Appendix A, 'Demonstration of Compliance with the Technical Information Requirements of the License Renewal Rule (10 CFR 54.21),'" dated October 18. 2001. BWRVIP-74-A is the NRC-approved version of the report.

Table B.2.28-1 lists the topical reports relevant to the RV and RV internal components, along with the date and ADAMS accession numbers for any NRC FSERs issued in approval of these topical reports:

Table B.2.28-1

Component	Reference	SER Date	SER Accession Number
RV Components	BWRVIP-74-A	10/18/01	ML012920549
RV Shells	BWRVIP–05	03/07/00	ML003690281
Core Shroud Support and Attachments	BWRVIP-38	03/01/01	ML010600211
Core Shroud	BWRVIP-76	Under Review	N/A
Nozzle Safe Ends and Piping	BWRVIP-75	09/15/00	ML003751105
Core Support Plate	BWRVIP-25	12/07/00	ML003775989
Core ΔP/Standby Liquid Control (SLC) Line and Nozzle	BWRVIP-27	12/20/99	ML993630179
Core Spray, Jet Pump Riser Brace, and Other Attachments	BWRVIP-48	01/17/01	ML010180493
Core Spray Lines and Spargers	BWRVIP-18	12/07/00	ML003775973
Top Guide	BWRVIP-26	12/07/00	ML003776110
Jet Pump Assemblies	BWRVIP-41	05/01/01	ML011310322
RV Lower Plenum Components	BWRVIP-47	12/07/00	ML003775765
Instrument Penetrations	BWRVIP-49	03/13/02	Fiche A9153/241-253
Integrated RV Surveillance:	BWRVIP-78 (40-Yr.)	02/01/02	ML020380691
- Plan	BWRVIP-116 (60-Yr.)	Under Review	N/A
- Implementation	BWRVIP-86	01/01/02	ML020380691

The applicant's "scope of program" program element did not specify which RV and RV internal components were within the scope of the RV&ISIP or which additional BWRVIP guidelines (i.e., in addition to BWRIP-74 and BWRVIP-94) were within the scope of the RV&ISIP relative to aging management of these components. The staff issued RAI B.2.28-1, Parts A, B, and C, dated May 18, 2005, to request clarification on which components and additional BWRVIP guideline documents are within the scope of the RV&ISIP and on the process to be taken if the applicant decides to deviate from the recommendations in pertinent NRC-approved BWRVIP topical reports.

The applicant provided its response to RAI B.2.28-1, Parts A, B, and C, by letter dated June 14, 2005. In its response to RAI B.2.28-1, Part A, the applicant confirmed that all of the components itemized in the bulleted list provided earlier in the section are within the scope of the RV&ISIP with the exception of the jet pump sensing lines.

The applicant also clarified that the CRD stub tube penetrations and incore flux monitor guide tubes were additional components that are within the scope of the RV&ISIP. For the jet pump sensing lines, the applicant originally took a position that the components, while within the scope of license renewal, do not require aging management because they are subject to daily surveillance requirements in accordance with the plant TS and because any potential failure of the lines would be detected as a result of the implementation of the TS surveillance requirements. The applicant added that the TS action statements would require that the facility be brought to Operating Mode 3 (hot standby) if one or more jet pump sensing lines were determined to be inoperable.

The applicant provided a supplemental response to RAIs B.2.28-1, Part A, by letter dated July 18, 2005, that clarified that the RV&ISIP will be credited, along with the Water Chemistry Program, as the basis for managing cracking due to SCC and loss of material due to pitting and crevice corrosion in the jet pump sensing lines. The staff has provided a comprehensive discussion and basis in SER Section 3.1.2.3 for approving the Water Chemistry Program and the RV&ISIP as the AMPs for managing cracking due to SCC and loss of material due to pitting and crevice corrosion in the jet pump sensing lines. The staff concluded that the applicant's initial and supplemental responses to RAI B.2.28-1, Part A are acceptable because the applicant clarified which RV internal components are within the scope of the RV&ISIP (including the jet pump sensing lines, CRD stub tubes penetrations, and incore flux monitor guide tubes) and has clarified how the RV&ISIP, along with the Water Chemistry Program, will be used to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in the jet pump sensing lines. Therefore, the staff's concern described in RAI B.2.28, Part A, is resolved.

In its response to RAI B.2.28-1, Part B, the applicant clarified that, in addition to BWRVIP-74-A and BWRVIP-94, the following BWRVIP reports were within the scope of RV&ISIP:

- BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines"
- BWRVIP-25, "Core Plate Inspection and Flaw Evaluation Guidelines"
- BWRVIP-26, "Top Guide Inspection and Flaw Evaluation Guidelines"
- BWRVIP-27, "Standby Liquid Control System/Core ΔP Inspection and Flaw Evaluation Guidelines"
- BWRVIP-38, "Shroud Support Inspection and Flaw Evaluation Guidelines"
- BWRVIP-41, "Jet Pump Assembly Inspection and Flaw Evaluation Guidelines"
- BWRVIP-47, "Lower Plenum Inspection and Flaw Evaluation Guidelines"
- BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines"
- BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines"
- BWRVIP-76 "Core Shroud Inspection and Flaw Evaluation Guidelines"

The applicant also clarified that the collective scope of these reports provides the "Inspection and Flaw Evaluation Guidelines" for the components that were confirmed to be within the scope of the RV&ISIP, as confirmed in the applicant's response to RAI B.2.28-1, Part A. The applicant also clarified that the scope of the RV&ISIP includes the following process for updating the scope of an AMP pending the staff's review of BWRVIP reports submitted for staff approval:

> The governing BSEP procedure for the Reactor Vessel and Internals Structural Integrity Program states:

> Any required program changes (new or revised guidelines) should be incorporated into the program within 60 days of identification.

As indicated in SER Table B.2.28-1, with the exception of BWRVIP-76, these additional BWRVIP reports have been approved by the staff as being acceptable for implementation by BWR utilities, including BSEP. Therefore, it is acceptable to include them within the scope of the RV&SIP. The applicant's commitment for the RV&ISIP includes a commitment to implement the NRC-approved version of BWRVIP-76 as part of the AMP once the report is finalized and approved by the staff (see Commitment Item #22). This is acceptable because the commitment is consistent with the BWRVIP implementation process for license renewal. The applicant's procedural step to incorporate any new or revised guidelines into the program confirms that the AMP includes measures to update the program for those unapproved BWRVIP reports that have been determined to be important to ensuring the integrity of a particular RV or RV internal component or commodity group of components and are pending NRC approval for implementation. This is acceptable to the staff.

In its supplemental response to RAI B.2.28-1, Part B, by letter dated July 18, 2005, the applicant added Topical Report BWRVIP-03, "BWR Vessel and Internals Project, Reactor Vessel and Internals Examination Guidelines," to the scope of the RV&ISIP because the report provides the basis for performing the UT examinations of the core plate rim hold-down bolts from the side of the core plates, which is an exception orientation of UT examinations recommended for these bolts in NRC-approved Topical Report BWRVIP-25. The staff's basis for accepting the recommended inspections in BWRVIP-03 for the examinations of the core plate rim hold-down bolts is given in the section titled "Technical Evaluation of the Applicant's Responses to AAIs on Applicable BWRVIP Topical Reports," subsection "Evaluation of the Applicant's Response to AAI 4 and 5 on BWRVIP-25."

The applicant also added Topical Report BWRVIP-139 to the scope of the RV&ISIP, because the report provides the applicant's augmented aging management strategy for the NSR steam dryers. This report is currently under review by the staff for acceptance. The staff's basis for accepting the recommended inspections in BWRVIP-139 for the examinations of the Units 1 and 2 steam dryers is given in the staff's evaluation of the "detection of aging effects" and "monitoring and trending" program elements for the RV&ISIP, subsection "Augmented Aging Management Activities for Non-Safety-Related RV Internal Components."

The list of BWRVIP topical reports that are within the scope of the RV&ISIP are either those that have been approved for implementation by the staff or those that are pending NRC acceptance through the BWRVIP report and BWR industry initiative acceptance process. The applicant clarified which additional BWRVIP topical reports are within the scope of the RV&ISIP. Based on the above, and the applicant's commitment regarding the BWRVIP topical reports, the staff found that RAI B.2.28-1, Part B, resolved and the program attribute acceptable.

The "scope of program" program element for the RV&ISIP states that the AMP is based on the BWRVIP's implementation guidelines in Topical Report BWRVIP-94. In RAI B.2.28-1, Part C, the staff requested confirmation that the scope of the RV&ISIP includes the following process for taking exceptions to NRC-approved BWRVIP recommendations:

> Each utility will inform the NRC of any decision to not fully implement a BWRVIP guideline approved by the NRC staff within 45 days of the report approval.

> The NRC should be notified if changes are made to the vessel and internals program that affect implementation of the BWRVIP guidelines.
>
> Flaw evaluations that deviate from guidance in BWRVIP reports shall be submitted to the NRC for approval.

The applicant provided the following response to RAI B.2.28-1, Part C, by letter dated June 14, 2005:

> The governing BSEP procedure for the Reactor Vessel and Internals Structural Integrity Program incorporates the recommendations from the best available guidance from the BWRVIP. These recommendations are within the scope of the BSEP responses to AAI No. 1 on Topical Report Numbers: BWRVIP-74-A, -18, -25, -26, -27, -38, -41, -47, -48, and -49.

Although the applicant did not confirm applicability of the information requested by the staff, the "scope of program" program element for the RV&ISIP clearly indicates the implementation guidelines of BWRVIP-94 are within the scope of the RV&ISIP. Since BWRVIP-94 includes the above reporting processes for deviating from, or making changes to, the BWRVIP inspection and evaluation guidelines that are within the scope of the RV&ISIP, the staff concluded that no additional confirmation of this is necessary, and RAI B.2.28-1, Part C, is resolved.

(2) Preventive Actions

The applicant stated that it implemented control of water chemistry to reduce the susceptibility of the RV and RV internal components to SCC (including IGSCC or irradiation assisted stress corrosion cracking (IASCC). The applicant stated that control of water chemistry is performed in accordance with the latest BWRVIP guidelines but did not specify which water chemistry guideline was being implemented for water chemistry control. In RAI B.2.28-2, dated May 18, 2005, the staff requested the applicant to clarify whether the Water Chemistry Program was also being used to mitigate the susceptibility of the RV and RV internal components to corrosive type of loss of material mechanisms, such as pitting corrosion or crevice corrosion. The staff also requested identification of the specific guideline document being used for water chemistry control.

By letter, dated June 14, 2005, the applicant clarified that TR-103515, Revision 2 is currently being implemented for water chemistry purity and control purposes and that the Water Chemistry Program is credited with the management of loss of material due to general, pitting, or crevice corrosion (in addition to management of flow blockage or cracking due to SCC, IGSCC, or IASCC). The applicant also clarified that the Water Chemistry Program will be supplemented to incorporate the recommendations in updated versions of this report as they are released by EPRI for implementation. Since the applicant has clarified which water chemistry guideline is being implemented for water chemistry control, RAI B.2.28-2 is resolved. The staff has evaluated the Water Chemistry program in Section 3.0.3.2.1 of this SER and has concluded that the applicant's Water Chemistry Program is an acceptable mitigative AMP for managing cracking and loss of material in BSEP components that are within the scope of license renewal. Based on this assessment, the staff concludes that the "preventive actions" program element is acceptable for implementation because the applicant will use the Water Chemistry Program to minimize the concentrations of impurities that, if left uncontrolled, could potentially induce these aging mechanisms in the RV internal components.

(3) Parameters Monitored or Inspected

The BWRVIP guideline documents address the intended functions of the RV and RV internal components, identify all aging effects that are applicable to these components, and propose recommended inspections for those components whose intended functions could be impacted by the aging effects applicable to the components. The applicant stated that the BWRVIP-developed inspection plans for the RV and RV internal components are based on the ability of the recommended inspection techniques to detect the aging mechanisms that are applicable to the components. The applicant's "parameters monitored or inspected" program element did not specify which aging effects/aging mechanisms are applicable to the RV and RV internal components within the scope of the RV&ISIP and are managed by the RV&ISIP. However, in the "scope of program" program element for this AMP, the applicant does identify that the RV&ISIP is used to manage the effects of cracking, loss of material, flow blockage, loss of pre-load, and reduction of fracture toughness in the RV and RV internal components. Since these aging effects have been identified in the "scope of program" program element, the staff has interpreted the RV&ISIP to also include these aging effects as being within the scope of the AMP's "parameters monitored/inspected" program element.

These aging effects are consistent with aging affects that are recommended for management in GALL AMP XI.M9, "BWR Internals Program," for RV and RV internal components and are consistent with the AERMs that been identified for the RV and RV internal components in LRA Table 3.1.2-1. Since these aging effects are consistent with the aging effects in GALL AMP XI.M9 and with the AERMs identified by the applicant in LRA Table 3.1.2-1, the staff concluded that the applicant has identified the applicable aging effects that are within the scope of, and are managed by, the applicant's RV&ISIP. Thermal fatigue of the RV and RV internal components is managed through the applicant's TLAA on Fatigue of ASME Code Class 1 and 2 components, which is discussed in LRA Section 4.3. The staff evaluated the TLAA on Fatigue of ASME Code Class 1 and 2 components in SER Section 4.3.

(4) and (5) Detection of Aging Effects and Monitoring and Trending

In the "detection of aging effects" and the "monitoring and trending" program elements, the applicant stated that the RV&ISIP uses a combination of ultrasonic, visual, and surface examinations to inspect the RV and RV internal components that are within the scope of the AMP. The applicant stated that the inspection methods and inspection frequencies used for the RV and RV internal components vary from component to component and will be consistent with the methods of examination and inspection frequencies specified in the applicable BWRVIP guidelines. The following subsections discuss the applicant's bases for performing augmented inspections of specific RV and RV internal components, as implemented in accordance with either (1) the BWRVIP topical reports that are within the scope of the RV&ISIP, (2) alternative inspection guidelines proposed by the Boiling Water Reactor Owners Group (BWROG) that have been approved by the NRC, or (3) other alternative bases for aging management that are evaluated in this section and approved for aging management.

- Augmented Inspections of the RV Feedwater Nozzles

The applicant stated that its inspections of the RV feedwater nozzles will be consistent with the methods of inspection and inspection frequencies specified in the BWROG, "Alternate BWR Feedwater Nozzle Inspection Requirements" report. This BWROG report provides the BWR industry's recommended guidelines for inspecting BWR feedwater nozzle components and was submitted for NRC approval on September 24, 1999. The staff approved the BWROG "Alternate BWR Feedwater Nozzle Inspection Requirements" report for implementation in its FSER to the BWROG dated March 10, 2000, (refer to ADAMS Accession Number ML003690673). Based on the staff's approval of the BWROG "Alternate BWR Feedwater Nozzle Inspection Requirements" report, the staff concluded that it is acceptable for the applicant to use the BWROG "Alternate BWR Feedwater Nozzle Inspection Requirements" report as the basis for managing cracking in the feedwater nozzles.

- Augmented Inspections of Top Guides

As an enhancement of the RV&ISIP, the applicant stated that BSEP will perform augmented inspections of the top guides (see Commitment Item #22). The applicant stated that the augmented inspections of the top guides will be performed using BWRVIP-26 and enhanced by VT-1 examination methods and that the sample sizes will be similar to those performed on the CRD guide tubes. The staff noted that the top guide in each unit is only a single component. In RAI B.2.28-3, dated May 18, 2005, the staff requested additional information on the criteria that will be used to define the sample size and inspection frequency for the inspections of the BSEP top guides and the criteria that will be used to select the top guide locations for inspection.

The applicant provided its response to RAI B.2.28-3 in Serial Letter 05-0071 dated June 14, 2005. The staff concluded that the response to RAI B.2.28-3 is acceptable because the applicant has clarified that inspections will be an enhanced VT-1 visual or a volumetric examination of those top guide locations in the areas that are expected to achieve the highest neutron fluence exposures and that the sample size will be 10 percent of the affected susceptible areas with 50 percent of the inspections scheduled to be completed within 6 years of the issuance of the staff's FSER on BWRVIP-26 (December 7, 2000) and 100 percent of the inspected areas being completed within 12 years of issuance of the staff's FSER on BWRVIP-26. Since all of this is consistent with the inspection and flaw evaluation guidelines of BWRVIP-26, the staff concluded that the details of the proposed inspections for the top guides are acceptable. Therefore, the staff's concern described in RAI B.2.28-3 is resolved.

- Augmented Inspections of Core Shroud Repair Clamps

The applicant performs augmented inspections of the core shroud repair bracket assemblies (core shroud repair clamps). In a letter dated June 23, 2000, (BSEP 00-0069), the applicant indicated that it inspects 25 percent of the core shroud repair clamps during scheduled refueling outages (RFOs) for Units 1 and 2. This appears to differ from the sample size recommended in BWRVIP-76 for BWR core shroud repair hardware assemblies. In the "monitoring and trending" program element for the RV&ISIP, the applicant stated that the following type of augmented inspections would be used for the examinations of the core shroud repair clamps during the periods of extended operation for BSEP:

> The examination of the Core Shroud Repair Brackets should consist of a VT-3 inspection of the locking devices, contact areas, bolting, and the overall condition of the component. Bolt tightness should be verified by visually examining the repair assembly and verifying that the threaded components are seated and that there are no unintended gaps at the tensioned member contact points.

In RAI B.2.28-4, dated May 18,2005, the staff requested clarification on why the percentage of core shroud repairs clamps currently inspected during each RFO was different from the recommendations on inspection sample size for core shroud repair assemblies in BWRVIP-76. The staff also inquired whether the applicant would continue its practice of performing augmented inspections of the core shroud repair clamps in each unit during scheduled refueling outages in the periods of extended operation, and if so, asked for the applicant to identify the inspection method(s), sample size, and inspection frequency that it will use for the augmented inspections of the core shroud repair clamps.

The applicant provided its response to RAI B.2.28-4 in Serial Letter BSEP 05-0071, dated June 14, 2005 (see Commitment Item #22). The applicant's response clarified that it is performing its inspections of the core shroud repair hardware in conformance with the augmented inspection criteria of BWRVIP-76. BWRVIP-76 is still pending staff approval as an acceptable inspection and flaw evaluation guideline for core shroud components and their repair hardware designs. However, the applicant's response is acceptable because the applicant has modified its original commitment for the RV&ISIP to implement BWRVIP-76 according to the recommendations and criteria in the NRC-approved version of the report, once the staff's review of the report has been completed. Therefore, the staff concern described in RAI B.2.28-4 is resolved.

- Augmented Aging Management Activities for BSEP-2 Spring-Loaded Core Plate Plugs

LRA Section 4.2.8 provides the applicant's TLAA for analyzing stress relaxation in the Unit 2 spring-loaded core plate plugs. In this TLAA, the applicant dispositioned the TLAA as being in compliance with 10 CFR 54.21(c)(1)(iii), in that the applicant opted to credit the RV&ISIP with the management of stress relaxation in the Unit 2 spring-loaded core plate plugs. In SER Section 4.2.8, the staff concluded that the RV&ISIP can be used to satisfy the criterion for TLAAs in 10 CFR 54.21(c)(1)(iii) and to manage stress relaxation in the Unit 2 core plate plugs. However, the applicant did not include any discussion in LRA Section B.2.28 on how the RV&ISIP will be used to manage stress relaxation in the Unit 2 spring-loaded core plate plugs during the period of extended operation for Unit 2. In RAI B.2.28-5, dated May 18,2005, the staff requested additional information on how the RV&ISIP would be used to manage stress relaxation in the Unit 2 spring-loaded core plate plugs.

In its response to RAI B.2.28-5, dated June 14, 2005, the applicant stated:

> In the response to RAI 4.2.8-1, Part A, and RAI 4.2.8-2 in BSEP letter to the NRC (Serial: BSEP 05-0050), dated May 4, 2005, BSEP stated that the Reactor Vessel and Internals Structural Integrity Program, discussed in BSEP LRA Section B.2.28, will manage loss of preload due to stress relaxation of the spring-loaded core plate plugs installed in Unit 2 by replacement.

The applicant provided additional information in its supplemental response to RAI B.2.28-5, by letter dated July 18, 2005:

> Based on current fluence projections, the replacement of the spring-loaded core plate plugs installed in Unit 2 will occur during the refueling outage that is currently scheduled for 2011. Any evaluation to extend the service life of the spring-loaded core plate plugs will be submitted to the NRC for review and approval.

The applicant's two responses to RAI B.2.28-5 clarify that the applicant's basis for managing stress relaxation in the Unit 2 spring-loaded core plate plugs will be to replace them with a welded configuration consistent with the core plate plug design in Unit 1 and that the replacement of the plugs is scheduled to be performed in the Unit 2 2011 refueling outage. The applicant included its program to replace the Unit 2 spring-loaded core plate welds for the RV&ISIP in Commitment Item #22. This is acceptable because loss of preload due to stress relaxation is not an applicable AERM for the welded core plate plug configurations and because the replacement activity will be performed prior to the period of extended operation for Unit 2. The staff's concern described in RAI B.2.28-5 is resolved.

- Augmented Inspections of the Welded Access Hole Covers

The AMR analysis in GALL Commodity Group item IV.B1.1-b, "Core Shroud and Core Plate," identified crack initiation and growth due to SCC, IASCC, or IGSCC as an AERM for welded access hole covers (AHCs). The AMR analysis recommends that GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," be used to manage these aging mechanisms in welded AHCs. In its discussion for the AMR, the staff emphasized that aging management strategies are to include augmented UT or other demonstrated acceptable examination methods of the AHC welds because cracking initiated in the crevice regions of the AHCs would not be amenable to visual inspection methods for BWR designs that include a creviced region in the AHCs. During the audit, the staff issued Audit Question 3.1-2 on aging management strategies for welded core plate AHCs:

> In LRA Table 3.1.2-1, Reactor Vessel and Internals, the cracking due to SCC in access hole cover (AHC) made out of nickel-based alloy and expose to reactor water is managed by the water chemistry program and the reactor vessel and internals structural integrity program. In the referenced LRA Table 1 item 3.1.1-32, the applicant also states that BSEP has only one welded AHC and cracking due to SCC in AHC will be managed by the ASME Section XI ISI program and the water chemistry program, which is consistent with the GALL recommendations. Clarify the discrepancy in the AMPs stated in the LRA Table 3.1.2-1 for the AHC and the LRA Table 1 item 3.1.1-32.

The applicant provided its response to Audit Question 3.1-2 , by letter dated March 14, 2005. In this letter, the applicant clarified that the procedures that implement the RV&ISIP include enhanced inspections of the access hole covers and that the inspections will be performed using either a ultrasonic test (UT) or an enhanced visual test-1 (EVT-1) (see Commitment Item #22).

The staff determined that there were two aspects of the applicant's response to Audit Question 3.1-2 that needed additional resolution. In Item (b) of the applicant's response to the audit question, the applicant indicates that an enhanced VT-1 visual examination technique may be used detect and monitor for cracking in the creviced region of the welded AHC. Yet the staff's discussion in GALL Commodity Group Item IV.B1.1-b stated that visual inspection techniques are not capable of detecting cracks that could initiate in the creviced regions of the AHC. In Item (c) of the applicant's response to the audit question, the applicant indicates that the RV&ISIP and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program are equivalent. While the staff would concur that the the RV&ISIP incorporates all of the applicable ASME Section XI inspections for the RV and RV internal components, the RV&ISIP also incorporates additional augmented inspections that are recommended by the BWRVIP as industry initiatives and that actually go beyond those inspections that are required by the ASME Code, Section XI. In RAI B.2.28-6, Part A, dated May 18, 2005, the staff inquired, relative to the staff's position in GALL Commodity Group line item IV.B1.1-b, how an enhanced VT-1 visual examination of the weld would be capable of detecting cracking in the creviced region of a welded AHC. In RAI B.2.28-6, Part B, dated May 18, 2005, the staff requested confirmation that the RV&ISIP is considered to be a more comprehensive inspection program for the RV and RV internals than is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

In its response RAI B.2.28-6 dated June 14, 2005 (Refer to Serial Letter BSEP 05-0071), the applicant provided information on how the augmented inspections of the welded AHCs would be performed. However, the applicant's response did not resolve the issue of how an enhanced VT-1 examination would be an acceptable examination technique for detecting cracks in the AHCs. To resolve this, the applicant supplemented its response to RAI B.2.28-6 with additional information in Serial Letter BSEP 05-0097, dated July 18, 2005. The applicant clarified that the augmented inspections of the welded AHCs will be performed using a volumetric examination method, either with or without an accompanying visual examination. The staff concludes that this is acceptable because the examination technique proposed by the applicant is consistent with the augmented inspection technique discussion in GALL Commodity Group line item IV.B1.1-b. RAI B.2.28-6 is resolved.

- Augmented Inspections of the Core Spray Sparger Nozzles to Monitor for Flow Blockage

The staff determined that the applicant's AMR for the core spray nozzles, as given in LRA Table 3.1.2-1, identified flow blockage as an AERM for the core spray nozzles and credited the RV&ISIP and the Water Chemistry Program with management of this aging effect. BWRVIP Topical Report BWRVIP-18-A, as approved in the NRC's FSER of December 7, 2000, provides the BWRVIP's recommended inspections and flaw evaluation methods for RV internal core spray lines and their components. The NRC-approved topical report focuses on the management of cracking and loss of material in these components but does not appear to focus on how flow blockage of the core spray nozzles will be managed. In RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Parts A and B, dated May 18, 2005, the staff requested clarification on how the RV&ISIP will be used to manage flow blockage in the core spray nozzles and possibly in the feedwater sparger nozzles.

In its response to RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part A, by letter dated June 14, 2005, the applicant stated:

> Part A: Corrosion products associated with loss of material are considered capable of impeding the flow of emergency coolant through the core spray nozzles. As shown in Table 3.1.2-1, flow blockage due to fouling is managed with a combination of the Water Chemistry Program and the Reactor Vessel and Internals Structural Integrity Program. The Water Chemistry Program mitigates the formation of corrosion products by controlling oxygen, chlorides, sulfates, etc. The verification that the Water Chemistry Program is effective is through the use of the Reactor Vessel and Internals Structural Integrity Program. The inspection of the core spray components is through BWRVIP-18-A. The NRC has previously found that the use of inspections per the BWRVIP guidelines is adequate.
>
> Section 2.3.2.3 of NUREG-1803, "Safety Evaluation Report Related to the License Renewal of the Edwin I. Hatch Nuclear Plant, Units 1 and 2," states:

In the call made on June 26, 2000, the staff expressed concern that blockage of the spray holes of the core spray spargers through aging could keep the core spray system from performing its intended function of spraying the fuel bundles following a LOCA, and thus may fail to provide adequate core cooling for the short- and long-term following the LOCA. The applicant replied that, because the core spray piping is made of stainless steel, corrosion is not a credible aging mechanism to cause flow blockage. The applicant further stated that BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines," provides a means to inspect the core spray piping. The staff believes that adequate long-term core cooling can only be assured by maintaining the original core spray distribution that was assumed for the CLB. The staff, therefore, will rely on the BWRVIP inspection program to provide reasonable assurance that the original spray distribution will be maintained during the period of extended operation.

Therefore, the combination of the Water Chemistry Program and the Reactor Vessel and Internals Structural Integrity Program will be effective in managing flow blockage due to fouling during the period of extended operation.

The applicant provided the following supplemental response to RAI B.2.28-7/RAI 3.1.2.3.1.2, Part A, by letter dated July 18, 2005, to clarify that the Water Chemistry Program was the AMP credited for aging management of flow blockage in core spray sparger nozzles and that the RV&ISIP was only being used to inspect for cracking or loss of material in the components (see Commitment Item #22):

The BSEP Water Chemistry Program has been effective in mitigating loss of material and cracking. The Chemistry Performance Index (CPI) was developed by the Institute for Nuclear Power Operations (INPO) to provide a single performance indicator for plant chemistry performance. This formula compares three factors monitored in BWR Feedwater/Reactor Water. These three factors are Final Feedwater Iron, Reactor Pressure Vessel (RPV) Sulfates and RPV Chlorides. These results are compared to INPO-compiled Industry Mean Values from 1993 for all BWR plants.

The BSEP CPI trend since 2002 has been:

	Unit 1	Unit 2
2002	1.049	1.036
2003	1.012	1.000
2004	1.169	1.000

Specific data on chemistry parameters follows:

Parameter	2002	2003	2004
RPV Chlorides			
Unit 1	0.504 ppb	0.301 ppb	0.351 ppb
Unit 2	0.499 ppb	0.331 ppb	0.236 ppb
FW Iron			
Unit 1	0.812 ppb	0.367 ppb	0.575 ppb
Unit 2	0.318 ppb	0.439 ppb	0.201 ppb
RPV SO_4			
Unit 1	2.046 ppb	1.686 ppb	1.990 ppb
Unit 2	1.779 ppb	0.891 ppb	0.469 ppb

> In addition, the structural integrity of the core spray spargers will be verified by performing inspections so that the original core spray distribution will be preserved during the extended period of operation.
>
> Therefore, the combination of the Water Chemistry Program and the Reactor Vessel and Internals Structural Integrity Program are effective in managing flow blockage due to fouling of the core spray nozzles.

The applicant's supplemental RAI response demonstrates that the applicant is controlling the concentrations of ionic impurities in the reactor coolant to concentrations of only 2 parts per billion (ppb) or less. These concentrations are lower than those for which EPRI recommends corrective action in Table 4-5a (no hydrogen water chemistry) or Table 4-5b (hydrogen water chemistry) of EPRI BWR water chemistry guidelines being implemented by the applicant (refer to the discussion of the "preventive actions" program element). Thus, the applicant is maintaining the Units 1 and 2 reactor coolant system water at a high purity level. Based on this analysis, the staff concludes that Water Chemistry Program will be sufficient by itself to manage flow blockage of the core spray sparger nozzles because, at these concentrations, the Water Chemistry Program will preclude the precipitation of corrosion products which otherwise could potentially lead to blockage of the core spray sparger nozzles orifices.

Currently, the RV&ISIP is not a sufficient AMP to credit with management of flow blockage in these nozzles because the inspections recommended in Topical Report BWRVIP-41 for the core spray sparger nozzles do not include visual inspections of the core spray sparger nozzle orifices to look for corrosion products that might be blocking the flow paths. However, the staff does conclude that the augmented inspections of the core spray sparger structural welds, as implemented in accordance with BWRVIP-41, will be sufficient to assure the structural integrity of the core spray sparger nozzles during the periods of extended operation for BSEP because the NRC has approved the augmented inspection recommendations in BWRVIP-41 in its SE to the BWRVIP dated May 1, 2001. Therefore, the staff's concern described in RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part A is resolved.

In its response to RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part B, by letter dated June 14, 2005, the applicant clarified that the feedwater spargers are designed with flow holes in lieu of nozzles. Therefore, the staff does not consider flow blockage to be a concern for the feedwater spargers. Based on this assessment, the staff agreed with the applicant and concluded that flow blockage is not an AERM of concern for the feedwater spargers. Therefore, the staff's concern described in RAI B.2.28-7/3.1.2.3.1.2-3, Part B, is resolved.

- Augmented Aging Management Activities for Non-Safety-Related RV Internal Components

The staff noted that, in LRA Table 3.1.2-1, the applicant identified that cracking due to SCC and/or IASCC and loss of material due to pitting or crevice corrosion are applicable AERMs for four NSR RV internal components: (1) the steam dryers, (2) the core shroud heads and separators, (3) the internal feedwater spargers, and (4) the RV surveillance capsule holders. The staff also determined that the applicant credited the RV&ISIP and the Water Chemistry Program with the management of these aging effects/aging mechanisms during the periods of extended operation. The staff determined that the current set of BWRVIP topical reports does not address aging management strategies and activities for these NSR RV internal components. In RAI B.2.8-8, Parts A and B, dated May 18, 2005, the staff requested that the applicant provide additional information on how the RV&ISIP would be used to manage cracking due to SCC or IASCC and loss of material due to pitting and crevice corrosion in the steam dryers, core shroud heads and separators, internal feedwater spargers, and RV surveillance capsule holders.

The applicant provided its response to RAI B.2.28-8 in Serial Letter BSEP 05-007, dated June 14, 2005, as supplemented its response with additional information in Serial Letter BSEP 05-0097, dated July 18, 2005. The applicant's response indicated that the Water Chemistry Program will be credited for aging management of the steam dryers, feedwater nozzle spargers, core shroud head and separators, and surveillance capsule holders. The staff evaluated the Water Chemistry Program in SER Section 3.0.3.1.

In the applicant's responses to RAI B.2.28-8, the applicant also credited the RV&ISIP for aging management regarding loss of material and cracking in the steam dryers and committed to implementing the recommendations of Topical Report BWRVIP-139 (the Inspection and Flaw Evaluation Guidelines for Steam Dryers) once the inspection guidelines are reviewed and approved by the NRC (see Commitment Item #22). The applicant intends to follow the recommended guidelines in topical report BWRVIP-139 for the RV&ISIP. The commitment was provided in the applicant's supplemental response to RAI B.2.28-15, Part B, dated July 18, 2005 (see Commitment Item #22). This is acceptable because the applicant's commitment will ensure that the inspections of the steam dryers will follow the augmented inspection guidelines of Topical Report BWRVIP-139, once the report is approved by the staff, and the FSER on the report is issued to the BWRVIP. Therefore, RAI B.2.28-8 is resolved with respect to performing augmented inspections of the stream dryers.

For the feedwater spargers, the applicant credited the RV&ISIP for aging management through use of the inspection guidelines that are established in the BWROG "Alternate BWR Feedwater Nozzle Inspection Requirements" report, which were issued by the BWROG and approved by the staff (refer to the NRC FSER of March 10, 2000, which may be accessed through ADAMS Accession Number ML003690673) to conform to the recommendations in NUREG-0619, "BWR Feedwater Nozzle and Control Rod Return Line Nozzle Cracking" (see Commitment Item #22). This is an NRC-recommended inspection program for BWR feedwater nozzle and spargers and is acceptable. RAI B.2.28-8 is resolved with respect to performing augmented inspections of the feedwater nozzles and spargers.

The applicant did not initially couple any inspection-based AMP with its proposal to credit the Water Chemistry Program with aging management of the NSR RV surveillance capsule holders and the core shroud heads and separators. To correct this, the applicant proposed in its supplemental response to RAI B.2.28-8 to credit a one-time inspection of these components. This is acceptable because these components are not highly loaded and because industry experience has not yet indicated that cracking due to SCC, IGSCC, or IASCC or that loss of material due to general, pitting, or crevice corrosion are AERMs for these components. The staff evaluates the One-time Inspection Program in SER Section 3.0.3.1 of this SER.

As indicated in the applicant's AMRs for RV attachment welds, aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in the structural welds attaching the surveillance capsule holders to the reactor vessel will be accomplished using the Water Chemistry Program and augmented inspections of BWRVIP-74-A, as invoked by the RV&ISIP and approved by the staff in its SE on BWRVIP-74. RAI B.2.28-8 is resolved with respect to performing augmented inspections of the NSR RV surveillance capsule holders and the core shroud heads and separators.

(6) Acceptance Criteria

The applicant stated that the acceptance criteria for the RV&ISIP are those that are specified in the specific BWRVIP inspection and flaw evaluation guidelines that are within the scope of the AMP. Progress Energy's commitment to participate and implement the recommend guidelines that are established by the BWRVIP is given the generic BWRVIP commitment letter of May 30 1997, from Mr. Carl Terry, Chairman of the BWRVIP to Dr. Brain Sheron, U.S. Nuclear Regulatory Commission. The letter commits Progress Energy to implementing those BWRVIP inspection and flaw evaluation guidelines that have been approved by the staff (see Commitment Item #22). The BWRVIP inspection and flaw evaluation guidelines that are within the scope of the RV&ISIP have been approved by the staff. These NRC-approved guidelines provide the flaw evaluation acceptance criteria for evaluating degradation that may be detected as a result of the applicant's implementation of these guidelines. For those BWRVIP inspection and flaw evaluation guidelines that are pending staff approval, the applicant has committed to implement the NRC-approved versions of the BWRVIP guidelines once they have been approved by the staff and the approved versions have been issued by the BWRVIP for implementation (see Commitment Item #22). Based on the applicant's commitments to implement the BWRVIP inspection and flaw evaluation guidelines that are within the scope of the RV&ISIP, the staff concluded that the "acceptance criteria" program element for the RV&ISIP is acceptable.

(7) Operating Experience

The applicant provided the following discussion in the "operating experience" program element for the RV&ISIP:

> The OE of BSEP mirrors that of the BWR fleet. The program guidelines outlined in applicable BWRVIP documents are based on evaluation of available OE information, including BWR inspection results and information on the elements that cause degradation. This information is used to determine which components may be susceptible to cracking and loss of material and to enhance inspection strategies, as applicable. Implementation of the Program provides reasonable assurance that the aging effects will be adequately managed so the intended functions of the reactor vessel and internals components will be maintained consistent with the CLB for the period of extended operation.

The BWRVIP's industry initiatives and topical reports for BWR RV and RV internal components were developed to summarize pertinent age-related degradation operating experience for BWR RV and RV internal components and to provide the BWR industry with a series of recommended augmented inspection and evaluation activities that would be equivalent to those required by the ASME Code, Section XI, or would go beyond the requirements of the ASME Code, Section XI. The staff's evaluation of the [Scope of Program] attribute for this AMP summarizes the BWRVIP Reports that are within the scope of the RV&ISIP. The BWRVIP Reports provide acceptable summaries and evaluations of the operating experience that is applicable to the BSEP RV internals. Therefore, the applicant's response is acceptable because BWRVIP reports address the relevant operating experience for BSEP RV internals.

In response to a recommendation that was raised in Advisory Committee on Reactor Safeguards (ACRS) Correspondence Letter ACRS-2091 to the Commission, dated September 14, 2004, the applicant included the steam dryers within the scope of license renewal. The applicant provided an AMR for the steam dryers in LRA Table 3.1.2-1 and credited the RV&ISIP and the Water Chemistry Program with the management of cracking and loss of material that could occur in the components during the periods of extended operation The staff's evaluation of the applicant's basis for managing cracking due to SCC and loss of material due to pitting and crevice corrosion of the steam dryers has been discussed in the staff evaluation of the "detection of aging effects" and "monitoring and trending" program elements for this AMP under the subsection titled, "Augmented Aging Management Activities for NSR RV Internal Components." The staff's evaluation includes the staff's basis for accepting resolution of RAI B.28-8 on aging management of the steam dryers.

Since the applicant addressed the operating experience that is relevant to BWRVIP augmented inspection recommendations and the BWR steam dryer experience and issue that was discussed in ACRS Correspondence Letter ACRS-2091, the staff concluded that the applicant's "operating experience" program element for the RV&ISIP is acceptable.

(8) Evaluation of the Applicant's Responses to AAIs on Applicable BWRVIP Topical Reports

The applicant also provided a number of tables in AMP B.2.28 that discuss the applicant's responses to the AAIs that are given in the staff's FSERs on specific BWRVIP Guideline Documents. These tables include:

- Table 1 - Responses to AAIs on BWRVIP-74-A, *BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal*
- Table 2 - Responses to AAIs on BWRVIP-18, *BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines*
- Table 3 - Responses to AAIs on BWRVIP-25, *BWR Core Plate Inspection and Flaw Evaluation Guidelines*
- Table 4 - Responses to AAIs on BWRVIP-26, *BWR Top Guide Inspection and Flaw Evaluation Guidelines*
- Table 5 - Responses to AAIs on BWRVIP-27, *BWR Standby Liquid Control System / Core Plate ΔP Inspection and Evaluation Guidelines*
- Table 6 - Responses to AAIs on BWRVIP -38, *BWR Shroud Support Inspection and Flaw Evaluation Guidelines*
- Table 7 - Responses to AAIs on BWRVIP-41, *BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines*
- Table 8 - Responses to AAIs on BWRVIP-47, *BWR Lower Plenum Inspection and Flaw Evaluation Guidelines*
- Table 9 - Responses to AAIs on BWRVIP-48, *BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines*
- Table 10 - Responses to AAIs on BWRVIP 49, *Instrument Penetration Inspection and Flaw Evaluation Guidelines*

The staff evaluated the applicant's responses to these AAIs. With respect to the applicant's responses to the AAIs, the staff found that the applicant had in all cases properly identified the AAIs and provided an acceptable bases for responding to and resolving the required renewal actions raised in the AAIs, with the following exceptions:

- AAI No. 1 on BWRVIP Topical Reports BWRVIP-74-A,-18, - 25, -26, -27, -38, -41, -47, -48, and -49: "The LR applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP report to manage the effects of aging on the functionality of the reactor vessel instrument penetrations during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this BWRVIP report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1)."

  The applicant stated that BSEP participates in the BWRVIP activities and that, as such, the BWRVIP initiatives are applicable to BSEP. The applicant stated that, for current and future open issues between the BWRVIP and the NRC, BSEP will work as part of the BWRVIP to resolve these issues generically with the staff. The applicant stated that if it is determined that exceptions to full compliance with the recommended guidelines of a BWRVIP report is warranted, BSEP will notify the NRC of the exception(s) to the guidelines within 45 days of receipt of the NRC's FSER and approval of the applicable BWRVIP guideline report.

  The staff determined that the "scope of program" program element for the RV&ISIP states that Topical Report BWRVIP-94 is within the scope of the AMP.

  In RAI B.2.28-1, Part C, the staff requested confirmation that these BWRVIP-94 recommendations are within the scope fo the RV&ISIP and the scope of the applicant's collective responses to Applicant AAI No. 1 on Topical Reports BWRVIP-74-A, -18, -25, -26, -27, -38, -41, -46, -47, -48, and -49. The staff's evaluation of the "scope of program" program element for this AMP has included its basis for confirming that the RV&ISIP includes these processes and the basis for resolving RAI B.2.28-1, Part C. Since the staff has concluded that the RV&ISIP includes these processes, RAI B.2.28-1, Part C is resolved and the applicant's generic response to AAI No. 1 on BWRVIP Topical Reports BWRVIP-74-A, -18, - 25, -26, -27, -38, -41, -47, -48, and -49 is acceptable.

- AAI No. 2 on BWRVIP Topical Reports BWRVIP-74-A,-18, - 25, -26, -27, -38, -41, -47, -48, and -49 : "10 CFR 54.21(d) requires that the UFSAR supplement for the facility must contain a summary description of all programs and activities for managing the effects of aging and all evaluations of TLAAs for the period of extended operation. Applicants for license renewal referencing applicable BWRVIP topical reports are to ensure that the programs and activities specified as necessary in the reports are summarily described in the UFSAR supplement."

The applicant's response to the AAI stated that the UFSAR supplement will include a summary description of the programs and activities specified as necessary in the BWRVIP reports.

10 CFR 54.21(d) requires applicants to include an UFSAR supplement summary description only for each AMP and TLAA that is within the scope of an LRA but not necessarily for each topical report that is identified as being within the scope of an AMP or TLAA. In RAI B.2.28-9, dated May 18, 2005, the staff recommended that the applicant make the following revision to its generic response to AAI No. 2:

> To satisfy the requirements of 10 CFR 54.21(d), the UFSAR Supplement for the BSEP-1/2 LRA includes a summary description for each AMP and TLAA that is within the scope of the LRA. Should the scope of a specific AMP or TLAA invoke a specific BWRVIP report as a subset of the AMP or TLAA, the summary description will state that CP&L is an active participant in the BWRVIP programs, and that CP&L will implement the guidelines of the applicable BWRVIP report, as approved in the NRC's final safety evaluation report on the specific BWRVIP guideline.

In RAI B.2.28-9, the staff also informed the applicant that amending the AAI response as recommended would make the AAI response consistent with the requirements of 10 CFR 54.21(d) and the manner in which BSEP has worded the UFSAR supplement summary descriptions for its AMPs and TLAAs to comply with the Rule.

In its response, dated June 14, 2005, the applicant stated :

> BSEP will update its response to Applicant Action Item 2, for each of the applicable BWRVIP reports, based on the recommendations. Also see the response to RAI B.2.28-15 below.

Since the applicant complied with the UFSAR supplement summary description requirement of 10 CFR 54.21(d) and has indicated that it would change its generic response to AAI No. 2 to reflect compliance with these requirements, the staff concluded that the applicant has satisfied generic AAI No. 2 on BWRVIP Topical Reports BWRVIP-74-A, -18, - 25, -26, -27, -38, -41, -47, -48, and -49 and RAI B.2.28-9 is resolved.

- AAI No. 6 on BWRVIP-74-A : "The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program that includes inspection and water chemistry. BWRVIP-29 describes a water chemistry program that contains monitoring and control guidelines for BWR water that is acceptable to the staff. BWRVIP-29 is not discussed in the BWRVIP-74 report. Therefore, in addition to the previously discussed BWRVIP reports, LR applications shall contain water chemistry programs based on monitoring and control guidelines for reactor water chemistry that are contained in BWRVIP-29."

The applicant stated that the BWR Stress Corrosion Cracking Program includes water chemistry control as a preventive measure and that the Water Chemistry Program is implemented in accordance with the latest guidelines of the BWRVIP. In RAI B.2.28-2, dated May 18, 2005, on the “preventive actions” program element for the RV&ISIP, the staff requested that the applicant identify by title and number which water chemistry guideline or guidelines were being implemented for water chemistry control. The staff identified that the RAI was also applicable to the applicant’s response to AAI No. 6 on BWRVIP-74-A.

In its response to RAI B.2.28-2, by letter dated June 14, 2005 (Refer to Serial Letter BSEP 05-0071), the applicant confirmed that the Water Chemistry Program includes implementation of the EPRI BWR water chemistry guidelines in report TR-103515, Revision 2. These water chemistry guidelines are invoked in GALL AMP XI.M2, “Water Chemistry,” as being acceptable for implementation. The staff’s evaluation of the “preventive actions” program element for this AMP has included its basis for resolving RAI B.2.28-2 based on this confirmation. Since the applicant identified that an acceptable EPRI BWR water chemistry guideline report is being implemented as part of the Water Chemistry Program, the staff concluded that RAI B.2.28-2 is resolved with respect to the applicant’s response to AAI No. 6 on BWRVIP Topical Report BWRVIP-74-A and the response to the AAI, as amended by the RAI response, is acceptable.

- <u>AAI Nos. 4 and 5 on BWRVIP-25</u>: In AAI No. 4 on BWRVIP-25, the staff stated that “due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.”

  In AAI No. 5 on BWRVIP-25, the staff stated that “until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.”
  In its response to AAI No. 4 on BWRVIP-25, the applicant stated that the susceptibility of the core plate rim hold-down bolts was evaluated as a potential TLAA, but no TLAA was identified by the applicant for these components. In Section 3.5 of the staff’s FSER on BWRVIP-25, dated December 7, 2000, the staff made the following determination with respect to potential TLAAs for core plate rim hold-down bolts:

  > The susceptibility of the rim hold-down bolts to stress relaxation results in a potential Time Limiting Analysis Aging (TLAA) issue. The rim hold-down bolts connect the core plate to the core shroud. The BWRVIP evaluated this issue under 10 CFR 54.21(c)(1)(ii) by projecting the analysis to the end of the period of extended operation. The stress state analyses, calculated for a 60-year plant life, indicated that all but two BWR/3s would undergo a five to 19 percent reduction in stress (e.g., loss of preload). However, two BWR/3s with core plate bolts positioned closer to the active fuel would show a 54 to 74 percent stress reduction. <u>The staff agrees that stress relaxation in the rim hold-down bolts is a TLAA issue and must be identified and evaluated by individual applicants considering license renewal</u>.

  In RAI 4.2.8-1, Part B, dated April 8, 2005, the staff requested that the applicant provide its technical justification for concluding why management of stress relaxation in the core plate rim hold-down bolts was not identified as a TLAA for the facility. The applicant's response to RAI 4.2.8-1, Part B, is applicable to the evaluation of AAI No. 4 on BWRVIP-25. In the applicant's response to RAI 4.2.8-1, Part B, dated May 4, 2005), the applicant stated that the integrity of 48 intact but un-preloaded core plate rim hold-down bolts is necessary to maintain the lateral alignment of the core plate, but clarified that the integrity of the bolts does not require maintenance of an adequate preload on the bolts and therefore is not dependent on an evaluation of the impact of accumulated neutron fluence level on the preload level. Based on the staff's evaluation in SER Section 4.2.8 and the applicant's response to RAI 4.2.28-1, Part B, the staff has concluded that the applicant does not need to include a TLAA for the core plate rim hold-down bolts because the structural integrity of the bolts and the bolts' ability to maintain the lateral alignment of the core plates does not rely on maintenance of an adequate pre-load. Therefore, the staff concluded that the applicant's response to AAI No. 4 on BWRVIP-25, as amended by the reponse to RAI 4.2.28-1, Part B, is acceptable in that a TLAA is not necessary to manage stress relaxation in the core plate rim hold-down bolts.

In its response to AAI No. 5 on BWRVIP-25, the applicant stated that an analysis by BSEP determined that only 48 of the 72 rim hold-down bolts in each of the core plates were needed to maintain the lateral alignment of the plates. The applicant stated that it confirms the presence of an adequate number of bolts by performing a UT inspection of the outside diameter of the core support ring. The examination performed by BSEP to assure the lateral alignment of the core plates and the structural integrity of rim hold-down bolts is different from that recommended by the BWRVIP in Topical Report BWRVIP-25 because the examination is performed from an orientation different from that recommended in BWRVIP-25. In RAI B.2.28-11, Parts A and B, dated May 18, 2005, the staff inquired whether this alternative examination method has been identified as an exception to the recommendations of BWRVIP-25 and to request a basis that demonstrates that the UT of the outside diameter of the core plate support ring would be capable of detecting potential cracking and/or stress relaxation in the bolts.

In its response, dated June 14, 2005, the applicant clarified that the core plate rim hold-down bolts were not relied on for structural integrity of the core plates and that instead the core plate rim hold-down bolts were relied upon only to prevent lateral displacement. As indicated in the response to AAI No. 5 on BWRVIP-25, the applicant stated that a BSEP-specific mechanical engineering evaluation has determined that only 48 of 72 intact bolts are relied upon to maintain the position of the core plate against lateral displacement and, as discussed in the previous paragraphs, that the integrity of the BSEP core plates does not rely on maintenance of a preload on the bolts, thus eliminating the need for a TLAA on stress relaxation of the bolts.

In the applicant's supplemental response to RAI B.2.28-11, Parts A and B, dated July 18, 2005 (Refer to Serial Letter BSEP 05-0097), the applicant clarified that, contrary to the recommendations of BWRVIP-25, the UT inspections of the core plate rim hold-down bolts from the side of the core plates are justified because the bolts are only relied upon for maintaining the lateral position of the core plates and because maintenance of an adequate preload is not a prerequisite for accomplishing this. The applicant's supplemental response also clarifies that these UT examinations will be done in accordance Section 8.4.4 of Report BWRVIP-03, which was approved in the NRC's SE on BWRVIP-03 dated June 8, 1998, as amended in the NRC's supplemental SE on

BWRVIP-03 dated July 15, 1999. The applicant's supplemental response to RAI B.2.28-1, Part B, has added Topical Report BWRVIP-03 to the list of BWRVIP reports that are within the scope of the RV&ISIP. The applicant's supplemental response to RAI B.2.28-15, Part A, dated July 18, 2005, has amended the UFSAR supplement summary description for the RV&ISIP (as provided in LRA Section A.1.1.30) to account for the inclusion of BWRVIP-03 within the scope of license renewal of the AMP.

The NRC's SE on BWRVIP-3 provides the basis for accepting the inspections of the core plates and its bolts from the outside surfaces of the core plates. Based on this assessment, the staff concluded that the UT inspections recommended in BWRVIP-03 for the BSEP core plate rim hold-down bolts are acceptable to confirm that the position of the bolts are sufficient to protect the core plates against lateral displacement. Based on this assessment, the UT examinations recommended in BWRVIP-03 for the core plate rim hold-down bolts are acceptable and the applicant's response and supplemental response to RAI B.2.28-11, Parts A and B, are resolved. The staff also concluded that the applicant's response to AAI No. 5 on BWRVIP-25, as amended by the RAI responses, is acceptable.

- <u>AAI No. 4 on BWRVIP-26</u>: "Due to IASCC susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue."

In its response to AAI No. 4 on BWRVIP-26, the applicant stated that portions of the top guides at BSEP-Units 1 and 2 already exceed the BWRVIP's threshold for potential initiation of IASCC; therefore, these components are considered susceptible to IASCC. The applicant stated that no TLAA was identified for the top guides. In its response to this AAI item, the applicant also stated that BSEP will perform augmented inspections of the top guides, as defined in the applicant's enhancement of the RV&ISIP. The staff evaluated this enhancement in its evaluation of detection of the aging effects and "monitoring and trending" program elements for the RV&ISIP.

In Section 3.5 of the staff's FSER on BWRVIP-26, dated December 7, 2000, the staff made the following determination with respect to potential TLAAs for top guide assemblies:

> One of the mechanisms that can cause degradation of the top guide assembly design is IASCC, due to the high fluence that exists at the grid beam locations. The BWRVIP-26 report found that the projected minimum end-of-life fluence at the grid beam location after 48 EFPY of operation (assuming 60 years at 80 percent capacity factor) is approximately 6 x 10^{21} n/cm^2 (E > 1 MeV), which surpasses the approximated threshold fluence level for IASCC of 5 x 10^{20} n/cm^2 (E > 1 MeV). <u>The staff agrees that the accumulated neutron fluence is a TLAA issue and must be identified and evaluated by individual applicants considering license renewal</u>.

Thus, in the staff's FSER on BWRVIP-26, dated December 7, 2000, the staff concluded that IASCC of the top guides, as impacted by the accumulated neutron fluence for the components, must be treated as a TLAA as defined in 10 CFR 54.3.

The applicant’s response to AAI No. 4 on BWRVIP-26 indicates that the applicant has reviewed the CLBs and did not identify any safety analyses in the CLBs that are specifically related to management of IASCC in the BSEP top guides and that meet the definition of a TLAA, as defined in 10 CFR 54.3. Based on this determination, the staff concludes that any TLAA submitted by the applicant to respond to this AAI item (i.e., any submittal of a TLAA on management of IASCC in the top guides) would be beyond the CLBs (beyond-CLB) for the facilities.

In RAI B.2.28-3, dated May 18, 2005, the staff requested additional information on the criteria that will be used to define the sample size and inspection frequency for the inspections of the BSEP top guides and the criteria that will be used to select the top guide locations for inspection. In its response to RAI B.2.28-3 dated June 14, 2005 (Refer to Serial Letter BSEP 05-0071), the applicant indicated that it is committed to performing augmented inspections of the BSEP-top guides to monitor for cracking in the components and has committed to performing these inspections in accordance with the version of BWRVIP-26 that has been approved by the staff (refer to the staff’s FSER on BWRVIP-26, dated December 7, 2000. This commitment is discussed as an enhancement to the RV&ISIP and was included in Enclosure 1 to CP&L Serial Letter No. BSEP 04-0006, dated October 18, 2004, as amended in the applicant’s supplemental response to RAI B.2.28-15, Part B, dated July 18, 2004 (See Commitment Item #22). In its response to RAI B.2.28-3, the applicant also indicated that inspection frequencies and sample size for the top guide inspections will be in accordance with the NRC-approved version of BWRVIP-26 and that the selection of locations will be based on those locations in the top guides that are projected to have the highest neutron fluences (E > 1.0 MeV) at the expiration of the periods of extended operation. This strategy for managing IASCC in the top guides addresses the issue raised in AAI No. 4 on BWRVIP-26 and will ensure that the proposed inspections will monitor for cracking in those top guide locations that have the highest probability of initiating IASCC. The neutron fluence methodology for the RVs and RV internal components has been approved by the staff and is assessed in SER Section 4.2.1.

Based on this assessment, the staff concluded that the applicant has taken a conservative approach to manage IASCC of the top guides and concludes that the applicant’s aging management strategy is an acceptable alternative to providing a beyond-CLB TLAA for the facilities, as it otherwise might have been done to satisfy AAI No. 4 on BWRVIP-26. AAI No. 4 on BWRVIP-26 is therefore considered resolved.

- <u>AAI No. 4 on BWRVIP-27</u>: “Due to the susceptibility of the subject components to fatigue, applicants referencing the BWRVIP-27 report for license renewal should identify and evaluate the projected fatigue cumulative usage factors as a potential TLAA issue.”

  In its response to AAI No. 4 on BWRVIP-27, the applicant stated that fatigue of the shroud supports was included as a TLAA in LRA Section 4. The BWRVIP issued BWRVIP-27 to provide the U.S. BWR industry with recommended guidelines and flaw evaluation criteria for SLC/core ΔP line penetrations to BWR RVs. The scope of the topical report does not cover core shroud supports. Thus, any response by the applicant to AAI No. 4 on BWRVIP-27 should have referenced the need to assess whether a TLAA regarding fatigue usage is needed for the SLC/core ΔP line penetrations of the Units 1 and 2 RVs.

Therefore, in RAI B.2.28-13/RAI 4.3-1, staff requested that the applicant provide its basis for concluding that a TLAA fatigue analysis would not be necessary for the SLC/core ΔP lines.

In the applicant's response to RAI B.2.28-13/RAI 4.3-1 dated June 14, 2005 (Refer to Serial Letter BSEP 05-0071), the applicant clarified that the SLC/core ΔP nozzles and internal lines were determined to be exempt from a fatigue evaluation for the RV and RV internal components, and that the staff accepted this in its evaluation of the BSEP TLAA on metal fatigue and of the applicant's response to RAI 4.3-1. Based on this assessment, the staff concludes that a TLAA on metal fatigue of the SLC/core ΔP nozzles and internal lines does not need to be included within the scope of the LRA. The staff evaluates the TLAA on metal fatigue of RV, RV internal, and other ASME Code Class components in SER Section 4.3. Based on this assessment, RAI B.2.28-13/RAI 4.3-1 is resolved; and the applicant's response to AAI No. 4 on BWRVIP-27, as amended by the RAI response, is closed.

- AAI No. 4 on BWRVIP-47: "Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF [cumulative usage factor] as a potential TLAA issue."

  In its response to AAI No. 4 on BWRVIP-27, the applicant stated that the applicant did not identify any fatigue-related TLAAs for the RV internal lower plenum components. In Section 3.5 of the staff's license renewal FSER on BWRVIP-47, the staff made the following statement on whether a TLAA on fatigue of the RV internal lower plenum components would be needed in an LRA for a BWR:

  > The BWRVIP-47 report stated that some plants may have lower plenum pressure boundary component fatigue cumulative usage factors (CUF) greater than the 1.0 threshold specified in NUMARC 90-02 for the license renewal term. For these plants, a plant-specific description of how this issue will be addressed will be needed.
  >
  > The BWRVIP-47 report further stated that, based on the above criteria, there are no generic TLAA issues that require evaluation for the lower plenum components."

  The staff needed to validate that a TLAA would not be needed for the RV internal lower plenum components. Therefore, in RAI B.2.28-14, dated May 18, 2005, the staff requested confirmation that the CUF for the RV internal lower plenum components was determined to be less than 1.0 for the design cycles assumed through 54 EFPY.

  In In its response to RAI B.2.28-14 dated June 14, 2005, the applicant clarified that the RV internal lower plenum components were determined to be exempt from a fatigue evaluation for the RV and RV internal components and that the staff accepted this in its evaluation of the BSEP TLAA on metal fatigue and of the applicant's response to RAI 4.3-1. Based on this assessment, the staff concludes that a TLAA on metal fatigue of the RV internal lower plenum components does not need to be included within the scope of the LRA. The staff evaluates the TLAA on metal fatigue of RV, RV internal, and other ASME Code Class components in Section 4.3 of this SER. Based on this assessment, RAI B.2.28-14 is resolved; and the applicant's response to AAI No. 4 on BWRVIP-47, as amended by the RAI response, is closed.

UFSAR Supplement. 10 CFR Part 54.21(d) requires that the UFSAR supplement for a facility LRA must contain a summary description for each AMP and TLAA that is proposed for aging management. The current UFSAR supplement summary description for the RV&ISIP, as identified in LRA Section A.1.1.30, is contained in the applicant's supplemental response to RAI B.2.28-15, Parts A and B, dated July 18, 2005 (Refer to Serial Letter BSEP 05-0097).

The updated UFSAR supplement summary description addresses the following additional descriptions that the staff concluded were necessary to ensure adequate aging management of the RV internals:

1. A statement that scope of the RV&ISIP includes conformance with and implementation of applicable BWRVIP Flaw and Inspection Guidelines, including BWRVIP-03, -18, -25, -26, -27, -38, -41, -47, -48, -49, -74-A, -76, -94, and -139 (when -139 is approved by the NRC).
2. A statement that the RV&ISIP will be used to manage loss of preload/stress relaxation in the BSEP-2 spring-loaded core plate plugs by replacing the BSEP-2 spring-loaded core plate plugs prior to entering the period of extended operation for BSEP-2. For the current UFSAR supplement summary description this is to be implemented during the 2011 refueling outage for BSEP-2 unless further justification is provided to defer the replacement activity.
3. A statement that the RV&ISIP will be used to manage loss of integrity due to cracking or loss of material and flow blockage of the core spray nozzles by implementing augmented inspections of the core spray nozzles during the periods of extended operation for Units 1 and 2 in conjunction with the Water Chemistry Program. To be consistent with the staff's evaluation of the "detection of aging effects" and "monitoring and trending" program attributes, management of flow blockage of the core spray sparger nozzles will be accomplished with the Water Chemistry Program and EPRI Report 103515, Revision 2, as invoked by the "preventive actions" program element for the RV&ISIP, and the integrity of the core spray sparger nozzles will be accomplished through implementation of the augmented inspections that are implemented in accordance with Topical Report BWRVIP-18, as approved by the staff.
4. A statement in the RV&ISIP, in conjunction with the Water Chemistry Program, will be used to manage cracking due to SCC and loss of material pitting and crevice corrosion in the NSR steam dryers and feedwater spargers, and a revision to the application to credit a one-time inspection, in conjunction with the Water Chemistry Program, will be used to manage these aging effects in the NSR core shroud heads and separators and RV surveillance capsule holders.

The applicant's supplemental response to RAI B.2.28-15, Part B, dated July 18, 2004, also revised the original commitment for the RV&ISIP that was initially provided in Enclosure 1 of CP&L Serial Letter No. BSEP 04-0006, dated October 18, 2004. The applicant's amended commitment for the RV&ISIP addressed four additionl aspects that are necessary because the augmented activities were either contained in a BWRVIP report that is pending acceptance by the NRC or not included in an existing NRC-approved BWRVIP or BWROG report. The four modifications of the original commitment for the RV&ISIP are as follows:

1. A statement that scope of the RV&ISIP includes conformance with and implementation of applicable BWRVIP Flaw and Inspection Guidelines, including BWRVIP-03, 18, -25, -26, -27, -38, -41, -47, -48, -49, -74-A, -76, and -94, as approved by the NRC.
2. A statement that the RV&ISIP, in conjunction with Water Chemistry Program, will be used to manage flow blockage of the core spray nozzles by implementing augmented inspections of the core spray nozzles during the periods of extended operation.
3. A statement that the RV&ISIP will be used to manage cracking and loss of material in the NSR steam dryers and feedwater spargers during the periods of extended operation.
4. A statement that the RV&ISIP will manage loss of preload due to stress relaxation of the Unit 2 spring-loaded core plate plugs by replacement of the plugs with a welded design prior to entering the period of extended operation.

Since the applicant has addressed these items in the revised UFSAR supplement summary description and revised commitment for the RV&ISIP, the staff concluded the revised UFSAR supplement summary description is acceptable in accordance with 10 CFR 54.21(d) and that the applicant's implementation of RV&ISIP, as modified by the commitments for the AMP, will be sufficient to manage aging in the RV internal components during the period of extended operation.

Conclusion. On the basis of its review of the applicant's program, the staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Systems Monitoring Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.29, "Systems Monitoring Program." In the LRA, the applicant stated that this is an existing, plant-specific program.

The Systems Monitoring Program will manage aging effects such as loss of material and cracking for external surfaces of piping, heat exchangers, ductwork, tanks, and other mechanical components within the scope of license renewal. Specific guidelines for assessing the material condition of components during system engineer walkdowns will be provided prior to the period of extended operation. The aging effects will be managed through visual inspection and monitoring of external surfaces for component leakage, rust or corrosion products, cracking, peeling coatings, and corroded fasteners. These activities are conducted on a periodic basis to verify the continuing capability of in-scope components prior to the loss of component intended function. The Systems Monitoring Program is a plant-specific program and there is no comparable program in the GALL Report.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.29, regarding the applicant's demonstration of the Systems Monitoring Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

In RAI B.2.29-1, dated March 17, 2005, the staff stated: "the applicant stated that the Systems Monitoring Program is an existing, plant-specific program and there is no comparable SRP-LR program in place. The applicant further stated that the implementation of the Systems Monitoring Program will be accomplished by a new procedure to be developed before the period of extended operation." Therefore, the staff requested that the applicant provide the following information:

(A) Since the Systems Monitoring Program is an existing program, what is the frequency of inspection, and what are the inspection criteria for the current program?

(B) Among the 10 program elements, many element descriptions rely on a new procedure to be developed prior to the period of extended operation. For example, the applicant stated, in "Monitoring and Trending," that the new procedure to be developed will include guidance on inspection frequency, inspection criteria that focus on detection of aging effects, and trending to provide predictability of component degradation. The applicant was requested to clarify the differences between those elements to be developed in the new procedure and those in the existing program.

In its March 31, 2005, response to RAI B.2.29-1, the applicant stated:

> The Systems Monitoring Program requires that systems crediting the program are inspected on a frequency sufficient to identify age-related degradation prior to loss of intended function. While license renewal systems are typically inspected on a quarterly basis, an extended frequency can be justified for some systems. In general, inspections are scheduled and performed so the entire system is fully walked down at least once per operating cycle. Portions of systems not accessible due to reactor operation are inspected during refueling outages.
>
> The BSEP systems monitoring implementation procedure incorporates a checklist of inspection attributes associated with the item being inspected and potentially applicable degradation mechanisms. For example, piping and fittings are inspected for:
>
> - Pinhole leaks or seepage,
> - Exterior corrosion, scaling, or rust,
> - Missing or not fully engaged flange nuts, studs, or bolts,
> - Excessive sweating or condensation collecting on pipes,
> - Leaking on threaded connections,
> - Excessive pipe vibration or pipe movement, and
> - No appreciable loss of material or cracking.

With respect to the difference between those elements to be developed in the new procedure and those in the existing program, the applicant stated that, since the LRA was submitted, BSEP has developed a new procedure directing activities of the Systems Monitoring Program. This procedure incorporates the enhancement attributes and provides more detailed guidance relative to the 10 program elements of an AMP.

The staff reviewed the Systems Monitoring Program against the AMP elements found in SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the “corrective actions,” “confirmation process,” and “administrative controls” program elements are part of the site-controlled quality assurance program. The staff’s evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of Program - In LRA Section B2.29, the applicant stated that the scope of the Systems Monitoring Program activities will apply to indoor and outdoor areas of the plant that contain SSCs and/or commodities that are within the scope of license renewal. AMRs for affected systems credit the Systems Monitoring Program for managing the external surface aging effects of loss of material and cracking for components such as piping, valves, ductwork, pumps, tanks, filters, and heat exchangers. Walkdowns by system engineers will be an essential part of this program. The applicant also stated that the implementation of the Systems Monitoring Program will be accomplished by a new procedure. Before the period of extended operation, BSEP will develop a new procedure, and the administrative controls will be enhanced to provide inspection criteria that focus on visual detection of aging effects. The staff considered the scope of the program to be clearly defined and acceptable.

The staff confirmed that the “scope of program” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated, in LRA Section B2.29 that the Systems Monitoring Program is a condition monitoring program; thus, there is no preventive action. The staff agreed with the applicant’s statements.

The staff confirmed that the “preventive actions” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - In LRA Section B2.29, the applicant stated that engineering and other plant personnel will continue to inspect the surface conditions of mechanical system components, including closure bolting, through visual inspection and examination for evidence of defects and age-related degradation. The parameters monitored or inspected are selected based on AMR results, including plant and industry operating experience, to ensure that aging degradation which could lead to loss of intended function will be identified and addressed. Inspections will detect aging effects/mechanisms and qualify degradations. Identified aging effects include loss of material and cracking. The applicant also stated that piping systems will be monitored through visual inspection for evidence of leaks. Flexible HVAC connections will be monitored for cracking or other changes in material properties (including wear). Inspections performed during system walkdowns include an evaluation of the pipe

covering and environmental conditions to determine whether insulation should be removed to inspect the pipe. Insulation is not generally removed in support of system walkdowns unless there is reason to believe that the condition of the pipe is degraded. The applicant further stated that, before the period of extended operation, BSEP will develop a new procedure (1) identifying the specific parameters to be monitored or inspected and (2) providing inspection criteria that focus on detection of aging effects for the Systems Monitoring Program (see Commitment Item #23). Degradations discovered will be recorded, qualified, and dispositioned, as appropriate. Implementation of the Systems Monitoring Program with the new procedure provides a link between the inspection guidelines and the specific components and associated degradations. The new procedure provides reasonable assurance that the presence of aging effects will be detected and recorded.

The staff's review of LRA Section B.2.29 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.29-2, dated March 17, 2005, the staff asked whether the applicant will inspect the surface condition of the closure bolting through visual examination for evidence of defects and age-related degradation. The applicant further stated that identified aging effects include loss of material and cracking. Therefore, the staff requested that the applicant provide justification for not identifying loss of preload as an aging effect for closure bolting in various plant systems.

In its response, by letter dated March 31, 2005, the applicant stated that the Bolting Integrity Program is being revised to address staff concerns raised during the audit. The revised program considers that loss of preload is applicable to bolting, and manages this aging effect by incorporating program elements consistent with those described in the GALL Report (i.e., torquing/installation guidance, materials control, ASME Section XI inspections, etc.). The staff found the applicant's response to be acceptable; therefore, the staff's concern described in RAI B.2.29-2 is resolved.

The staff confirmed that implementation of the "parameters monitored or inspected" program element is in accordance with general industry practice and that the program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3; therefore, the staff concluded that this program element is acceptable.

(4) Detection of Aging Effects - In LRA Section B2.29, the applicant stated that the external surface condition of systems and components will be determined by visual inspection. Before the period of extended operation, a new procedure will be developed focusing on detection of aging effects for the Systems Monitoring Program. Thus, the Systems Monitoring Program is intended to detect degradation prior to component failure. As indicated in the response to RAI B.2.29-1, the applicant stated that the BSEP systems monitoring implementation procedure incorporates a checklist of inspection attributes associated with the item being inspected and potentially applicable degradation mechanisms that address aging effects identified by the license renewal aging management reviews. The staff considered this approach of detecting the aging effects for external surfaces of selected systems and components to be acceptable.

The staff confirmed that the “detection of aging effects” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - In LRA Section B2.29, the applicant stated that the new procedure to be developed will include guidance on inspection frequency, inspection criteria that focus on detection of aging effects, and trending to provide predictability of component degradation (see Commitment Item #23). This will ensure aging indicators are qualified so that trending continues to be done effectively. Data from detailed system and component material condition inspections will be trended and evaluated to identify and correct problems. The results of monitoring and trending activities will be documented. The staff agrees with the applicant’s approach for the monitoring and trending of the component degradation.

The staff confirmed that the “monitoring and trending” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - In LRA Section B2.29, the applicant stated that the acceptance criterion for visual inspections is the absence of anomalous indications that are signs of degradation. Responsibility for the evaluation of visual indications is assigned to engineering personnel. Evaluations of anomalies found during inspections determine whether analysis, repair, or further inspection is required. The applicant further stated that the new procedure will require an inspection checklist for SSCs inspected during system walkdowns (see Commitment Item #23). Inspection checklists and procedure instructions will require inspection attributes to be qualified. The new procedure will define when corrective action is required. The staff found the acceptance criteria for the program to be acceptable.

The staff confirmed that the “acceptance criteria” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - In LRA Section B2.29, the applicant stated that BSEP operating experience supports the fact that engineering personnel monitor and evaluate equipment and system performance through examination and trending of condition monitoring activities, reviewing equipment failure history, analyzing availability and reliability information, and performing system walkdowns. The applicant also stated that processes at BSEP are continually being upgraded based on industry operating experience and self-assessment. These processes will provide effective means of ensuring the system health for applicable license renewal systems.

The staff’s review of LRA Section B.2.29 identified an area in which additional information was necessary to complete the review of the applicant’s program elements. The applicant responded to the staff’s RAI, as discussed below.

In RAI B.2.29-3, dated March 17, 2005, the applicant was requested to provide some examples of actual plant-specific operating experience of appropriate actions taken to demonstrate and ensure the effectiveness of the existing Systems Monitoring Program.

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

> The World Association of Nuclear Operators (WANO) performed a peer review of BSEP in August, 2003. The peer review team observed the following strengths:
>
>> The system engineering organization has embraced a culture of identifying degrading system problems through system trending and monitoring. Problems are often identified before equipment failure through the use of advanced monitoring and trending software, process computer data and system engineering walkdowns. Trending successes are celebrated and rewarded to emphasize the culture. The use of advanced electronic system notebooks allows engineers to retrieve and store all trending and system information from many sources in one location, and provides a historical record for long-term monitoring.

An assessment of the Brunswick Engineering Support Section (BESS) at BSEP was performed on September 9 through September 20, 2002. The Brunswick Nuclear Assessment Section (BNAS) conducted an assessment of activities to determine the effectiveness of engineering personnel in support of BSEP and the performance monitoring of systems. This assessment was accomplished through performance-based, real-time observations, technical reviews, and interviews with personnel. As a basis for the assessment, the team used Institute for Nuclear Power Operations (INPO) 97-002, "Performance Objectives and Criteria for Operating and Near-Term Operating License Plants." The team's assessment concluded that BESS was effective in support of the operation of BSEP.

BNAS Report B-ES-02-01 provided the following details on the conduct of the BESS:

- Verified that engineering personnel monitor and evaluate equipment and system performance through examination and trending of condition monitoring activities,
- reviewing equipment failure history, analyzing availability and reliability information, and performing system walkdowns.
- Reviewed the process, status, and use of the Electronic System Notebook,
- Reviewed the age and number of work tickets on hold pending engineering resolution for timeliness and adequacy of engineering support, and
- Verified that engineering personnel support the effective maintenance of the plant, and that personnel are aware of, and proactively pursue, maintenance issues.

In a more recent self-assessment, BNAS Report B-ES-04-01 supports that BSEP System Engineering activities were effective in support of the operation of the BSEP, but noted several instances wherein walkdowns and trending were not properly performed and documented. The assessment identified the use of informal guidelines rather than procedural controls to ensure that system trending and monitoring is effectively implemented as a contributing factor in these findings. BSEP has addressed this issue by development of a formal site procedure for systems monitoring, including inspection frequency requirements, acceptance criteria, monitoring and trending, corrective actions, and documentation.

Based on the above descriptions, the staff's concern described in RAI B.2.29-3 is resolved, and the staff confirmed that the "operating experience" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10; therefore, this program element is acceptable.

UFSAR Supplement. In LRA A.2.2.31, the applicant provided the UFSAR supplement for the Systems Monitoring Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Systems Monitoring Program, the staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Preventive Maintenance Program

Summary of Technical Information in the Application. This AMP is described in LRA, Section B.2.30, "Preventive Maintenance Program." In the LRA, the applicant stated that this is an existing, plant-specific program.

The Preventive Maintenance Program provides for inspections of structures and components, or their replacement/refurbishment, during the performance of preventive maintenance activities. The program assures that various aging effects are managed for a wide range of components through scheduled inspections and predetermined criteria. The Preventive Maintenance Program includes inspections for blockage of flow, internal corrosion, fouling of heat exchangers, cracking, loss of material, loss of heat transfer, degradation of elastomers, and adverse impact on the function of nearby SR components. The components inspected or replaced as part of the Preventive Maintenance Program include heat exchanges, relief valves, strainers, filters, traps, sump pumps, rubber bladders, elastomer seals, and plate coils in containment penetrations.

The program administrative controls reference activities for monitoring SSCs to permit early detection of degradation. Data from walk-downs are trended and evaluated to identify and correct problems. In addition, the program includes periodic refurbishment or replacement of structures and components. The applicant credited the Preventive Maintenance Program for the aging management of selected components in the following systems: RHR system, HPCI system, SLC system, reactor building closed cooling water system, DG fuel oil system, DG lube oil system, DG jacket water system, DG starting air system, standby gas treatment system, HVAC DG building, HVAC reactor building, HVAC control building, service water intake structure, DG building, and control building.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.30 regarding the applicant's demonstration of the Preventive Maintenance Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Preventive Maintenance Program against the AMP elements found in SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - In LRA Section B.2.30, the applicant stated that this program is a plant-specific program that assures various aging effects are managed for a wide range of components, as specified by AMRs and credited in selected AMPs. In the LRA, the applicant provided a table that summarizes the activities for the systems that are within the scope of the Preventive Maintenance Program. The table includes the components that credit the Preventive Maintenance Program for management of specific aging effects. In particular, the program provides for periodic component replacement/refurbishment, inspection, and testing of components. The Preventive Maintenance Program may also be used to implement specific preventive maintenance activities required by other AMPs. The applicant will add or modify Preventive Maintenance Program activities, as necessary, to assure that age-related degradation will be managed for the systems/components for which the program is credited.

As documented in the BSEP Audit and Review Report, the applicant provided a list of the systems, component/commodity groups, intended functions, and aging effects/mechanisms managed by this program. The applicant also provided a list of the materials of construction for the component groups in the scope of the Preventive Maintenance Program and the environments to which the component groups are exposed.

The staff confirmed that the "scope of program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - In LRA Section B.2.30, the applicant stated that this program includes periodic refurbishment or replacement of components specified at an interval that assures no loss of intended function. As documented in the BSEP Audit and Review Report, the staff confirms that, where appropriate, the Preventive Maintenance Program contains inspections and testing activities used to identify component aging degradation effects.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - In LRA Section B.2.30, the applicant stated that this program consists of inspections, testing, and criteria used to identify component aging

effects. Where necessary, activities are specified on a component-specific basis to ensure that appropriate parameters are monitored based on anticipated aging effects. In addition, the applicant identified the inspection activities that monitor various parameters, such as surface condition, loss of material, corrosion, cracking, elastomer degradation, loss of heat transfer effectiveness, and adverse impacts on nearby SR components. In addition, the aging effects and mechanisms to be managed by the Preventive Maintenance Program are documented in the BSEP Audit and Review Report.

During the audit, the staff noted that examples of aging effects monitored by the Preventive Maintenance Program include visual inspections of the interior of the SLC system accumulator shells to identify corrosion, measurements of flow in HPIC minimum flow bypass lines to identify clogging, and visual examinations of elastomers to identify aging degradations, such as cracking.

In LRA Section B.2.30, the applicant stated an enhancement to its existing program that will add or modify the Preventive Maintenance Program, as necessary, to assure that age-related degradation will be managed for the components that credit the program. The applicant will complete these additions and modifications prior to the period of extended operations. As documented in the BSEP Audit and Review Report, the applicant stated that the Preventive Maintenance Program shall be created to insure structures and components will not adversely impact the function of nearby SR components. Examples of the additional structures and components include the service water building, circulating water intake structure sump pumps, and DG building sump pumps.

The staff reviewed and confirmed that this program element satisfies the criteria defined in SRP-LR Section A.1.2.3.3. The staff determined that the parameters inspected by the Preventive Maintenance Program for passive long-lived components are adequate to provide symptomatic evidence of potential degradation for timely replacement of components to prevent equipment failure. The staff also determined that the routinely scheduled replacement, or timely refurbishment of structures and components will maintain conditions such that their associated systems will be able to perform their intended functions during the period of intended operation. On this basis, the staff found that the applicant's "parameters monitored or inspected" program element is acceptable.

(4) Detection of Aging Effects - In LRA Section B.2.30, the applicant stated that this program provides inspection and test criteria identified during the AMRs that rely on the program for detection of the aging effects.

As documented in the BSEP Audit and Review Report, the applicant uses a database to identify the frequency of preventive maintenance, and to generate work orders. The work orders contain the component, the parameter monitored or inspected, the degradation being monitored, the procedure to conduct the inspection, and what data to collect. The work order also identifies the codes and standards, if any, that are associated with the activity, the techniques to be used, and the qualification requirements for the inspectors.

The staff also noted that the Preventive Maintenance Program activities include use of (1) ultrasonic flow meters to confirm that HPCI minimum-flow bypass valves are not excessively clogged; (2) visual inspections of elastomers to detect aging degradation effects, such as cracking; and (3) visual (VT-2) examinations of HPCI piping to identify corrosion.

In the LRA, the applicant stated that its Preventive Maintenance Program is a defined-scope program directed toward specified components. In systems where the scope is not defined at a component level (HVAC systems), inspection criteria will address representative or leading indicator conditions for the aging mechanism of concern. Degraded conditions would be addressed through the Corrective Action Program, including expansion of inspections and repairs, as necessary.

The staff reviewed and confirmed that this program element satisfies the criteria defined in SRP-LR Section A.1.2.3.4. The staff determined that the work orders provided links between the parameters and the aging effects being monitored. Also, the staff determined that the techniques used to detect aging effects are consistent with accepted engineering practice and, therefore, satisfy this program element. On this basis, the staff found that the applicant's "detection of aging effects" program element is acceptable.

(5) Monitoring and Trending - In LRA Section B.2.30, the applicant stated that this program's inspection intervals are specified, as necessary, to ensure that aging effects are detected prior to loss of intended functions. Condition monitoring is accomplished by generic procedural requirements, as well as by specific requirements contained in preventive maintenance activities.

As documented in the BSEP Audit and Review Report, the applicant uses the PassPort database to schedule and track preventive maintenance activities. Some work requests contain the acceptance criteria and the actions to be taken if the acceptance criteria are exceeded. In other cases, the work requests require the results of the monitoring or inspection activity to be forwarded to the system engineers for their review and action. The system engineers are responsible for reviewing and trending the results. The frequency of activities is adjusted by the system engineers on the basis of trending data from previous activities.

The staff confirmed that this program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The overall monitoring and trending techniques proposed by the applicant are acceptable on the basis that the inspections, replacements, and sampling activities described by the applicant will effectively manage the applicable aging effects. On this basis, the staff found that the applicant's "monitoring and trending" program element is acceptable.

(6) Acceptance Criteria - In LRA Section B.2.30, the applicant stated that the acceptance criteria are specified based on generic requirements and application-specific considerations, and are intended to ensure that an acceptable level of performance is maintained at all times.

The staff confirmed that this program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. The plant design-basis includes Code-specified acceptance criteria for applicable systems. On this basis, the staff found that the applicant's "acceptance criteria" program element is acceptable.

(10) Operating Experience - In LRA Section B.2.30, the applicant stated that operating experience has demonstrated that the Preventive Maintenance Program has been effective in maintaining component performance and function. The program is subject to continual improvement under corporate procedures and initiatives.

The GALL Report is based on industry operating experience through April 2001. Recent industry operating experience has been reviewed for applicability, and subsequent operating experience will be captured through the normal operating experience review process. In addition, periodic surveillance and preventive maintenance activities have been in place at BSEP since the plant began operation. These activities have proven effective at maintaining the material condition of SSCs and detecting unsatisfactory conditions. The applicant has a demonstrated history of detecting damaged and degraded components and causing their repair or replacement in accordance with the site corrective action process.

Furthermore, the applicant stated that it has performed a review of corrective actions for a 10-year period to investigate site operating experience relative to various AMRs performed. These reviews revealed that the Corrective Action Program had a limited number of corrective action reports identifying age-related degradation and failures. For those failures, corrective actions were taken that resulted in improvements to maintenance and operating procedures/practices, and prevented recurrence of the failures.

Also, as documented in the Audit and Review Report, the staff reviewed the applicant's corrective action report, which addressed degradation of the SLC system accumulators. In 1988, during an annual SLC accumulator bladder inspection, the applicant found surface corrosion on the interior shell of an SLC accumulator, and set up six-month inspection intervals for the SLC accumulators. On the basis of inspection results, the applicant calculated a corrosion rate in 1990 and determined that the next surveillance of the accumulators would be due on Unit 1 prior to December 5, 1992, and on Unit 2 prior to March 31, 1993.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the staff concluded that the applicant's Preventive Maintenance Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

<u>UFSAR Supplement</u>. In LRA Section A.1.1.32, the applicant provided the UFSAR supplement for the Preventive Maintenance Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's Preventive Maintenance Program, the staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for

the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Phase Bus Aging Management Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.31, "Phase Bus Aging Management Program." In the LRA, the applicant stated that this is a new, plant-specific program.

In the LRA, the applicant stated that the materials of construction for the phase bus components are:

- Aluminum
- Bronze
- Copper
- Galvanized Metal
- Porcelain
- Polyester Fiberglass
- Silicone Caulk
- Steel

The phase bus components are exposed to heat and oxygen (including ohmic heating)

Aging Effects - In LRA Table 3.6.2-1, the applicant identified oxidation, loosening of bolted connections due to thermal cycling, and corrosion due to moisture as the aging effects associated with phase bus components that require management.

Aging Management Program - The applicant will credit the Phase Bus AMP to manage the potential aging effects for the phase bus components. The applicant stated that the structural supports of the phase bus housing containing the electrical buses and bus supports are addressed in LRA Section 2.4 as civil/structural commodities.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.31 regarding the applicant's demonstration of the Phase Bus AMP to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff agreed that the applicant, in the LRA, correctly identified the aging effects associated with phase bus components. The staff also finds cracks, foreign debris, excessive dust built up, and evidence of water intrusion as additional aging effects addressed in the BSEP AMP.

The applicant will credit the Phase Bus AMP for aging management of in-scope iso-phase and non-segregated phase bus at BSEP. The program involves several activities conducted at least once every 10 years to identify the potential existence of aging degradation. Activities include sampling accessible bolted connections for adequate torque, visual inspections of the bus for signs of cracks, corrosion, or discoloration which may indicate overheating, and visual inspections of the bus enclosure for signs of corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The program applies to the iso-phase bus as well as nonsegregated 4.16KV and 480V phase bus within the scope of license renewal. The staff evaluated the aging management activity for the phase bus. The evaluation of the applicant's AMP focused on program elements rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven program elements: (1) scope of program, (2) preventive actions, (3) parameter monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (10) operating experience. The staff's evaluation of the applicant's corrective action confirmation process, and administrative controls is provided separately in SER Section 3.0.4.

(1) Scope of Program - This Program applies to the iso-phase bus as well as non-segregated 4.16KV and 480V phase bus within the scope of License Renewal. This is acceptable to the staff since the program will include all bus ducts within the scope of license renewal.

(2) Preventive Actions - The Phase Bus AMP is a condition monitoring program. No actions are taken as part of this program to prevent or mitigate aging degradation. The staff did not identify the need for such actions.

(3) Parameters Monitored or Inspected - In the LRA, the applicant stated that a sample of accessible bolted connections will be checked for adequate torque. Bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., are inaccessible and are not covered by this activity. This Program will also inspect the bus enclosure for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion (see Commitment Item #25). The bus itself will be inspected for signs of cracks, corrosion, or discoloration which may indicate overheating. The internal bus supports will be inspected for structural integrity and signs of cracking.

    The staff noted that vendors do not recommend the retorque of bolted connections unless the joint requires service or the bolted connections are clearly loose. The torque required to turn the fastener in the tightening direction (restart torque) is not a good indication of the preload once the fastener is in service. Due to relaxation of the parts of the joint, the final loads are likely to be lower than the installed loads.

    In light of the above concern, in RAI 3.6.2.3-1, dated May 18, 2005, the staff requested that the applicant provide technical justification of how retorquing of bolted connections is a good indicator of the preload once the fastener is in service. In its response, by letter dated June 14, 2005, the applicant stated that the proposed activity to retorque bolted connections, even on a sample basis, is contrary to vendor recommendations and good bolting practices discussed in EPRI Technical Report 1003471, December 2002, and EPRI Technical Report 104213, December 1995. In lieu of this, the contact resistance across accessible bolted connections at sample locations will be measured using a low-range ohmmeter. The program element "acceptance criteria" will be modified accordingly. The staff found that the applicant's response addresses the staff's concern regarding retorquing.

    In the LRA, the applicant stated that bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., are inaccessible and are not covered by this activity. In

RAI 3.6.2.3-1, the staff also requested that the applicant provide a method for detecting inaccessible bolted connections loosening due to thermal cycling or provide a technical justification of why inaccessible bolted connections are not subject to thermal cycling. In its response by letter dated June 14, 2005, the applicant stated that visual inspection of the inaccessible bolted connection is an appropriate technique for determining the condition of the joint. Inaccessible bolted connections will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The applicant proposed to visually inspect the inaccessible bolted connections (covered by heat shrink tape, sleeving, insulating boots, etc.). However, the applicant did not specify the frequency of this inspection nor the parameter monitored/inspected. The staff position is that bolted connections can be checked for loose connections by thermography or by measuring connection resistance using a low-range ohmmeter. Alternatively, bolted connections covered with heat sink tape, sleeving, insulating boots, etc., can be visually inspected for insulation material surface anomalies, such as discoloration, cracking, chipping or surface contamination. If visual inspection is performed to check bolted connections, the inspection shall be performed every five years and the first inspection shall be completed before the period of extended operation. During discussions with the applicant, the staff requested that the applicant provide the frequency of visual inspection and the criteria for the visual inspection. In response to the staff's information request, the applicant stated, by letter dated July 18, 2005, that accessible and inaccessible phase bus bolted connections will be checked for loose connections by thermography or by measuring connection resistance using a low-range ohmmeter on a 10-year frequency (see Commitment Item #25). Thermography will be performed while the bus is energized and loaded. The staff found the applicant's response acceptable because using thermography or measuring connections resistance will detect loosening of bolted connections due to ohmic heating.

The staff found that the visual inspection of bus ducts, bus bar, and internal bus supports will provide indications of aging effects. Additionally, using thermography or checking resistance of a sample of a bolted joint will provide reasonable assurance that bolted connections are not loose due to ohmic heating. The staff also found that the 10-year inspection frequency is an adequate period to preclude failures of bus ducts since industry experience has shown that the aging degradation is a slow process.

(4) Detection of Aging Effects - Following issuance of a renewed operating license for BSEP, this program will be completed before the end of the initial 40-year license term of September 8, 2016, for Unit 1 and December 27, 2014, for Unit 2; and every 10 years thereafter. The staff found that the 10-year inspection frequency is an adequate period to preclude failures of bus ducts since industry experience has shown that the aging degradation is a slow process.

(5) Monitoring and Trending - Trending actions are not included as part of this program. Trending of discrepancies will be performed as required in accordance with the Corrective Action Program. Corrective action is part of the Quality Assurance Program. The staff found this to be acceptable since trending will be performed under a controlled administrative process.

(6) Acceptance Criteria - Initially, in the LRA, the applicant state that accessible bolted connections must meet the minimum torque specification. Additional acceptance criteria include no unacceptable indications of cracks, corrosion, foreign debris, excessive dust buildup or discoloration which may indicate overheating or evidence of water intrusion. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of license renewal intended function. As discussed above, the staff expressed its concern about the retorquing of the bolted connections. The applicant revised the acceptance criteria to state that using thermography or checking resistance of a sample of bolted joint will provide reasonable assurance that bolted connections are not loose due to ohmic heating. The staff found the revised acceptance criteria to be acceptable.

(10) Operating Experience - This is a new AMP. There is no existing site-specific operating experience to validate the effectiveness of this program. Industry operating experience has shown that phase bus exposed to appreciable ohmic or ambient heating during operation may experience loosening of bolted connections related to the repeated cycling of connected loads or of the ambient temperature environment. This phenomenon can occur in heavily loaded circuits (i.e., those exposed to appreciable ohmic heating or ambient heating) that are routinely cycled. The staff found that the proposed program will provide reasonable assurance that bus ducts are not exposed to excessive ohmic or ambient heating.

UFSAR Supplement. In LRA Section B.2.31, the applicant provided the UFSAR supplement for the Phase Bus AMP. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's Phase Bus AMP, the staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.5 Fuel Pool Girder Tendon Inspection Program

Summary of Technical Information in the Application. This AMP is described in LRA Section B.2.32, "Fuel Pool Girder Tendon Inspection Program." In the LRA, the applicant stated that this is an existing, plant-specific program.

The Fuel Pool Girder Tendon Inspection Program is used to manage loss of prestress in the fuel pool girder tendons of each reactor building. The fuel pool girder tendons are not associated with the containment pressure boundary and are not within the scope of the ASME Section XI, Subsection IWL Program; however, the Fuel Pool Girder Tendon Inspection Program is conservatively based on guidance from the ASME Section XI, Subsection IWL Program. The program visually inspects and physically tests a representative sample of tendons. Inspection results are used to project an estimated loss of prestress through the next inspection period to ensure the tendon prestressing values do not fall below the minimum design requirements.

In describing the program, the applicant discussed the program in terms of the 10 elements described in SRP-LR. The applicant also plans to enhance the existing program during the period of extended operation.

On the basis of the program and its proposed enhancements, the applicant concluded that the Implementation of the program provides reasonable assurance that the loss of prestress will be adequately managed such that the fuel pool girder tendons will continue to perform their intended functions consistent with the CLB for the period of extended operation.

The program elements and the enhancements are discussed in LRA B.2.32.2.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.32, regarding the applicant's demonstration of the Fuel Pool Girder Tendon Inspection Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Fuel Pool Girder Tendon Inspection Program against the AMP elements found in SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (i.e., program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). These elements are discussed below.

(1) Scope of Program - In LRA Section B.2.32, the applicant stated that the Fuel Pool Girder Tendon Inspection Program applies to the BSEP fuel pool girder tendons and manages them for a loss of prestress (see Commitment Item #26).

    The staff initially had some reservation regarding the scope of program coverage. However, after reviewing the parameters monitored, the staff confirmed that the program includes periodic inspection of the tendon hardware components. The staff found this program element acceptable, as it will monitor the condition of BSEP fuel pool girder tendon hardware, and will monitor and trend the prestressing forces in the tendons.

    The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - In LRA Section B.2.32, the applicant stated that the Fuel Pool Girder Tendon Inspection Program is a condition monitoring program; thus preventive actions are not applicable.

    The staff considers the implementation of the program as a preventive measure against significant degradation of tendon hardware components. Therefore, the staff found the element description acceptable.

    The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - In LRA Section B.2.32, the applicant stated that the Fuel Pool Girder Tendon Inspection Program monitors/inspects the fuel pool tendons for loss of prestress. The monitored/inspected parameters include visual examination for corrosion, pitting, or deleterious conditions, physical testing of tendon lift-off values, filler grease, and destructive testing of a tendon wire for an ultimate strength determination (see Commitment Item #26).

The staff found the “parameters monitored or inspected” acceptable, as the monitoring of the essential parameters will manage the aging of the hardware components of the BSEP fuel pool girder tendons.

The staff confirmed that the “parameters monitored or inspected” program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - In LRA Section B.2.32, the applicant stated that detection of aging effects is performed by the Fuel Pool Girder Tendon Inspection Program by both visual inspection and physical testing performed on a frequency commensurate with ASME Code, Section XI, Subsection IWL.

The staff believes that the implementation of the program commensurate with that for the post-tensioning tendons in ASME Code Subsection IWL of Section XI will detect defects in the tendons’ hardware components and corrosion protection medium. Therefore, the staff found the element description acceptable.

The staff confirmed that the detection of aging effects program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - In LRA Section B.2.32, the applicant stated that the Fuel Pool Girder Tendon Inspection Program will require the loss of prestress to be trended to ensure the actual prestress does not fall below the minimum design allowable prior to the next inspection period.

The staff found the description in this element acceptable. In conjunction with the parameters monitored, keeping track of the trend in prestressing forces will help alert the applicant about the unusual behavior of the trend during the period of extended operation.

The staff confirmed that the “monitoring and trending” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - In LRA Section B.2.32, the applicant stated that the acceptance criteria for tested tendons is that the prestress values be above the minimum design requirements and are projected to be above the minimum design requirements through the next inspection period (see Commitment Item #26).

The staff's review of LRA Section B.2.32 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI B.2.32-1, dated March 17, 2005, the staff's request to the applicant is as follows:

> This inspection program includes monitoring parameters (as described in element Parameters Monitored) as well as monitoring prestressing force levels in the girders. The applicant is requested to provide its justification as to why the element Acceptance Criteria does not incorporate the acceptance criteria related to the tendon hardware components and corrosion

In its response, by letter dated March 31, 2005, the applicant stated that the subject tendons are not associated with the containment structure and do not support any pressure boundary intended function; as such, ASME Code Section XI, Subsection IWL, is not applicable. However, previous inspections of the tendons were performed using criteria based on ASME Code, Section XI, Subsection IWL, and inspections performed in accordance with the BSEP AMP will continue to use guidance based on ASME Code, Section XI, Subsection IWL.

The staff found the response acceptable, as the applicant will utilize the applicable provisions of Subsection IWL of Section XI of the ASME Code for acceptance criteria related to tendon hardware and corrosion protection medium. Therefore, the staff's concern described in RAI B.2.32-1 is resolved.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(7) Corrective Actions - In LRA Section B.2.32, the applicant stated that the corrective actions associated with a deficient inspection finding shall either re-tension the tendon, replace and tension the tendon, or perform an engineering evaluation. Corrective actions including root cause determinations and prevention of recurrence are done in accordance with the Corrective Action Program. Timeliness is monitored and is commensurate with the level of significance. Where evaluations are performed without repair or replacement, engineering analysis reasonably assures that the SSC intended function is maintained consistent with the CLB.

The applicant has provided adequate description of corrective actions, and with the enhancement to be implemented during the period of extended operation, the staff found the actions proposed in this element acceptable.

The staff confirmed that the "corrective actions" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.7. The staff concluded that this program attribute is acceptable.

(8) Confirmation Process - In LRA Section B.2.32, the applicant stated that confirmation of the effectiveness of this program is accomplished in accordance with the Corrective Action Program and Corporate Quality Assurance Procedures, review and approval

processes, and administrative controls implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

The adequacy of this element is discussed in SER Section 3.0.4.

(9) Administrative Controls - In LRA Section B.2.32, the applicant stated that BSEP quality assurance (QA) procedures, review and approval processes, and administrative controls implemented in accordance with the requirements of 10 CFR Part 50, Appendix B and will continue to be adequate for the period of extended operation.

The adequacy of this element is discussed in SER Section 3.0.4.

(10) Operating Experience - In LRA Section B.2.32, the applicant stated that the Fuel Pool Girder Tendon Inspection Program is an existing program; two inspections have been performed: one in 1995 and another in 2000, based on guidance from ASME Code, Section XI, Subsection IWL. The staff reviewed the tendon inspection in 1995 and found the program to be "conservative, technically sound, and thorough." Program improvements have been implemented as a result of past inspections. Industry issues associated with the management of prestressed tendon systems are reviewed and considered for applicability to the BSEP tendon system.

The staff's review of LRA Section B.2.32 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI, as discussed below.

In RAI B.2.32-2, dated March 17, 2005, the staff requested that the applicant provide a summary of the results of the last two inspections for Unit 1 and Unit 2 girders. The staff indicated that, as a minimum, the summary should include (1) the minimum required prestressing forces, (2) the sample size of the tendons inspected, (3) a table of measured prestressing forces, (4) chemical composition of grease (CPM) and free water in the grease, (5) strength values of the wires tested during inspections, and (6) condition of anchorages and the concrete around the anchorages.

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

> The tendon surveillance consists of an inspection of the physical condition of a selected sample of in-place tendons. Physical tendon surveillance consists of sheathing filler inspection, anchorage inspection, tendon lift-off, inspection and tensile testing of removed wire samples, and tendon retensioning with the tendons being resealed after completion of all inspections. The applicant stated that two surveillances have been performed on the tendons; the twenty-year surveillance performed in 1995, and the twenty-five year surveillance performed in 2000.

(1) Three values are provided for the minimum required prestressing forces based on the three stages of tendons used for each girder. The prestressing forces are Stage I: 582 kips, Stage II: 595 kips, and Stage III: 602 kips.

(2) The 1995 tendon inspection selected six tendons on each of the two girders per unit for visual examination. Three of the six tendons per girder were selected for lift-off. One of the lift-off tendons was de-tensioned for wire removal, visual examination, and tensile testing. Provisions for sample expansion were included based on BSEP 05-0044 inspection results (see Commitment Item #26). The 2000 tendon inspection sampled three tendons on each unit for physical inspection and three tendons for visual inspection. One tendon was selected for detensioning and wire removal.

(3)

Summary of Tendon Inspection Average Prestressing Values (kips)						
	Stage I		**Stage II**		**Stage III**	
	1995	2000	1995	2000	1995	2000
Unit 1	658	664	645.5	659	661.2	673
	648.1		655.5		660.7	
			646.6			
	Stage I		**Stage II**		**Stage III**	
	1995	2000	1995	2000	1995	2000
Unit 2	642.9	651	671.6	701	652.1	660
	710.9		682.5		666.7	
	647.9		706.5			
	610.8		681.4			
	641.6		666.4			
			656.4			

(4) Chemical Composition - 1995 inspection

The sheathing filler grease samples tested for water soluble ions showed acceptable levels of chloride, nitrate, and sulfide ions. Water content of grease in all tendons, except one tendon, was found to be acceptable. The old grease in the unacceptable tendon was replaced by pumping through with new Visconorust 2090 P4 grease.

Chemical Composition - 2000 Inspection

The sheathing filler grease samples tested for water soluble ions showed acceptable levels of chloride, nitrate, and sulfide ions and water content.

(5) The tensile tests of both the 1995 and 2000 inspections found the wire samples exhibited acceptable yield strength, ultimate strength, and elongation. All samples exceeded the yield and ultimate strength minimum values of 192,000 psi and 240,000 psi, respectively.

(6) Physical Condition - 1995 Inspection

For Unit 1, no sign of significant corrosion was found in the anchorheads, shims, or bearing plates of any of the tendon samples inspected. Concrete adjacent to the bearing plates was found covered with a steel plate and could not be inspected. For Unit 2, data gathered during this in-service inspection supports the conclusion that no abnormal degradation of the Unit 2 post-tensioning system affecting the structural integrity of the Unit 2 fuel pool girders has occurred during the first twenty years of service. Structural integrity has been maintained despite visual indications at the anchorage of grease leakage from defective grease cans and visual indications of corrosion on some of the anchorage components and surveillance wires.

Physical Condition - 2000 Inspection

Acceptable corrosion levels were found on all the tendon ends except for the buttonheads on one tendon. No cracks were found on any anchorage components. Concrete surrounding the bearing plates was covered with a steel plate and could not be inspected for cracks.

Based on these responses, the staff found that the applicant is appropriately monitoring the condition of post-tensioning system hardware and corrosion protection medium. The applicant plans to continue with monitoring of prestressing tendon forces, and condition monitoring of the post-tensioning system hardware during the period of extended operation. Therefore, the staff found the applicant’s response acceptable for this element of the program, and the concern described in RAI B.2.32-2 is resolved.

Enhancements. The applicant plans to enhance the program prior to the period of extended operation in the areas of (1) Parameters Monitored or Inspected, (2) Detection of Aging Effects, (3) Monitoring and Trending, (4) Acceptance Criteria, and (5) Corrective Action.

The staff review of the enhancements indicates that the enhancements are in the right direction, and the implementation of the program with the enhanced elements will ensure that the prestressing tendons of the fuel pool girders will perform their intended function during the period of extended operation.

UFSAR Supplement. In LRA Section A.1.1.34, the applicant provided the UFSAR supplement for the Fuel Pool Girder Tendon Inspection Program. The staff reviewed this section and determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

In RAI B.2.32-4, the staff noted that in LRA Section A.1.1.34, the applicant provided a summary of the inspection program. The summary, in part, stated: “Inspection results are used to ensure that the tendon prestressing values do not fall below the minimum design requirements.” The staff requested that the applicant provide the present projected values at 40 and 60 years (based on the two inspections), and the minimum required value that is required for the girders to perform their intended functions.

In response, the applicant explained that the loss of prestress is relatively steep from the initial loading to the first surveillance at 20 years and then levels off between the 20-year surveillance and the 25-year surveillance. The applicant further noted that no meaningful information could be derived for a 60-year prestress value from two data points taken less than half-way through the 60-year period. The 40- and 60-year values have been determined analytically, and the following table provides those values compared to the minimum required.

	Minimum Required Prestress	Initial Prestress	Predicted 40 year Prestress	Predicted 60 year Prestress
Stage I Tendons	581.6 kips	776.9 kips	616 kips	568 kips
Stage II Tendons	595.2 kips	783 kips	635.7 kips	587.7 kips
Stage III Tendons	602.2 kips	780 kips	639.7 kips	591.7 kips

In LRA Section 4.7.2, TLAA “Fuel Pool Girder Tendon Loss of Prestress,” the applicant indicated that it has analytically predicted the tendon forces for 40 and 60 years, as shown in the above table. In making a prediction for 60 years, the applicant increased the 40-year losses assumed due to concrete creep and shrinkage by 25 percent, and that due to relaxation of steel by 50 percent. Based on these estimates, as seen in the table above, the 60-year prestressing forces in all tendons are likely to be less than the minimum required prestressing force. The applicant plans to monitor the forces, and plans to take appropriate actions, when the forces are found to be below the minimum required forces. The staff found the approach taken by the applicant acceptable.

Conclusion. On the basis of its review and audit of the applicant’s Fuel Pool Girder Tendon Inspection Program, the staff concluded that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

Pursuant to 10 CFR 54.21(a)(3), a license renewal applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. Three of these 10 attributes are associated with the QA activities of corrective action, confirmation process, and administrative control. Table A.1-1, “Elements of an Aging Management Program for License Renewal,” of Branch Technical Position IQMB-1 provides the following description of these quality attributes (see Commitment Item #1):

- Corrective actions, including root cause determination and prevention of recurrence, should be timely.
- The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Administrative controls should provide a formal review and approval process.

SRP-LR, Branch Technical Position IQMB-1, “Quality Assurance For Aging Management Programs,” noted that those aspects of the AMP that affect quality of SR SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for NSR SCs subject to an AMR, the existing 10 CFR Part 50, Appendix B, QA program may be used by the applicant to address the elements of corrective action, confirmation process, and administrative control. Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

- SR SCs are subject to 10 CFR Part 50, Appendix B, requirements which are adequate to address all quality-related aspects of an AMP consistent with the CLB of the facility for the period of extended operation.
- For NSR SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its 10 CFR Part 50, Appendix B, program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the UFSAR supplement in accordance with 10 CFR 54.21(d).

3.0.4.1 Summary of Technical Information in Application

LRA Section 3.0, "Aging Management Review Results," provides an AMR summary for each unique structure, component, or commodity group determined to require aging management during the period of extended operation. This summary includes identification of AERMs and AMPs utilized to manage these aging effects. LRA Appendix A, “Updated Final Safety Analysis Report Supplement,” and LRA Appendix B, “Aging Management Programs,” demonstrate how the identified programs manage aging effects using attributes consistent with the industry and NRC guidance. The applicant’s programs and activities that are credited with managing the effects of aging can be divided into three types of programs: existing, enhanced, and new AMPs.

In LRA Section A1.1, “Aging Management Programs and Activities,” the applicant discussed that the QA program implements the requirements of 10 CFR Part 50, Appendix B, and that the program elements of “corrective action,” “confirmation process,” and “administrative controls” apply to both SR and NSR SSCs that are within the scope of license renewal. In LRA Section B.1.3, “Quality Assurance Program and Administrative Controls,” the applicant discussed the implementation of its 10 CFR Part 50, Appendix B, QA program, which includes the program elements of “corrective action,” “confirmation process,” and “administrative control,” and is applicable to the SR and NSR SSCs that are subject to AMR.

Corrective Action. Corrective actions are implemented through the initiation of an Action Request (AR) in accordance with plant procedures established to implement the Corrective Action Management Policy and requirements of 10 CFR 50, Appendix B, Criterion XVI. Conditions adverse to quality, such as, failures, malfunctions, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to prevent recurrence. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented are documented and reported to appropriate levels of management.

Confirmation Process. The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions and preclude repetition of significant conditions adverse to quality. The Corrective Action Program includes the requirement that measures be taken to preclude repetition of significant conditions adverse to quality. These measures will include actions to verify effective implementation of proposed corrective actions. The confirmation process is part of the Corrective Action Program and, for significant conditions adverse to quality, includes:

- reviews to assure proposed actions are adequate
- tracking and reporting of open corrective actions
- root cause determinations
- reviews of corrective action effectiveness

The AR process is also monitored for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of a follow-up AR.

Administrative Control. Administrative controls that govern aging management activities are established within the document control procedures that implement (1) industry standards related to administrative controls and quality assurance for the operational phase of nuclear power plants, and (2) the requirements of 10 CFR 50, Appendix B, Criterion VI.

3.0.4.2 Staff Evaluation

The staff reviewed LRA Appendices, Sections A1.1 and B1.3. The purpose of this review was to assure that the SRP-LR Section A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1),” regarding QA attributes of AMPs. Based on the staff’s evaluation, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in LRA Sections A1.1 and B1.3; the staff concluded that the program descriptions are consistent with the staff’s position and the Branch Technical Position discussed in IQMB-1.

3.0.4.3 Conclusion

The staff found that the QA attributes of the applicant’s AMPs are consistent with 10 CFR 54.21(a)(3). Specifically, the applicant described the quality attributes of the programs and activities for managing the effects of aging for both SR and NSR SSCs within the scope of license renewal and stated that the 10 CFR Part 50, Appendix B, QA program provides the elements of corrective action, confirmation process, and administrative control. Therefore, the applicant’s QA description for its AMPs is acceptable.

3.1 <u>Aging Management of Reactor Vessel, Internals, and Reactor Coolant System</u>

This section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and reactor coolant system (RCS) components and component groups associated with the following systems:

- reactor vessel and internals
- neutron monitoring system
- reactor manual control system
- CRD hydraulic system
- reactor coolant recirculation system

3.1.1 Summary of Technical Information in the Application

In LRA Section 3.1, the applicant provided AMR results for components. In LRA Table 3.1.1, "Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the reactor vessel, internals, and RCS components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and RCS components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the Audit and Review Report and are summarized in SER Section 3.1.2.1.

During the audit, the staff reviewed the AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.1.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.1.2.2.

During the audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating (1) whether all plausible aging effects were identified, and (2) whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.1.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.1.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the reactor vessel, internals, and RCS components.

Table 3.1-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.1, that are addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Internals, and Reactor Coolant System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor coolant pressure boundary components (Item 3.1.1-01)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Steam generator shell assembly (Item 3.1.1-02)	Loss of material due to pitting and crevice corrosion	Inservice inspection; water chemistry		Not applicable, PWR only
Isolation condenser (Item 3.1.1-03)	Loss of material due to general, pitting, and crevice corrosion	Inservice inspection; water chemistry		Not applicable (See Section 3.1.2.2)
Pressure vessel ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E > 1 MeV) (Item 3.1.1-04)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G of 10 CFR 50 and RG 1.99	TLAA	This TLAA is evaluated in Section 4.2, Reactor Vessel Neutron Embrittlement
Reactor vessel beltline shell and welds (Item 3.1.1-05)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor vessel surveillance	Reactor Vessel Surveillance Program (B.2.14), TLAA	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2)
Westinghouse and B&W baffle/former bolts (Item 3.1.1-06)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	Plant specific		Not applicable, PWR only

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Small-bore RCS and connected systems piping (Item 3.1.1-07)	Crack initiation and growth due to SCC, intergranular SCC, and thermal and mechanical loading	Inservice inspection; water chemistry; one-time inspection	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program (B.2.1) Water Chemistry Program (B.2.2)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2)
Jet pump sensing line, and reactor vessel flange leak detection line (Item 3.1.1-08)	Crack initiation and growth due to SCC, intergranular stress corrosion cracking (IGSCC), or cyclic loading	Plant specific	Water Chemistry Program (B.2.2) One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends further evaluation (See Section 3.1.2.2)
Isolation condenser (Item 3.1.1-09)	Crack initiation and growth due to stress corrosion cracking (SCC) or cyclic loading	Inservice inspection; water chemistry		Not applicable (See Section 3.1.2.2)
Vessel shell (Item 3.1.1-10)	Crack growth due to cyclic loading	TLAA		Not applicable, PWR only
Reactor internals (Item 3.1.1-11)	Changes in dimension due to void swelling	Plant specific		Not applicable, PWR only
PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads, and nozzles for the steam generator instruments and drains (Item 3.1.1-12)	Crack initiation and growth due to SCC and/or primary water stress corrosion cracking (PWSCC)	Plant specific		Not applicable, PWR only
Cast austenitic stainless steel (CASS) reactor coolant system piping (Item 3.1.1-13)	Crack initiation and growth due to SCC	Plant specific		Not applicable, PWR only
Pressurizer instrumentation penetrations and heater sheaths and sleeves made of Ni-alloys (Item 3.1.1-14)	Crack initiation and growth due to PWSCC	Inservice inspection; water chemistry		Not applicable, PWR only

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Westinghouse and B&W baffle former bolts (Item 3.1.1-15)	Crack initiation and growth due to SCC and IASCC	Plant specific		Not applicable, PWR only
Westinghouse and B&W baffle former bolts (Item 3.1.1-16)	Loss of preload due to stress relaxation	Plant specific		Not applicable, PWR only
Steam generator feedwater impingement plate and support (Item 3.1.1-17)	Loss of section thickness due to erosion	Plant specific		Not applicable, PWR only
(Alloy 600) Steam generator tubes, repair sleeves, and plugs (Item 3.1.1-18)	Crack initiation and growth due to PWSCC, ODSCC, and/or IGA or loss of material due to wastage and pitting corrosion, and fretting and wear; or deformation due to corrosion at tube support plate intersections	Steam generator tubing integrity; water chemistry		Not applicable, PWR only
Tube support lattice bars made of carbon steel (Item 3.1.1-19)	Loss of section thickness due to FAC	Plant specific		Not applicable, PWR only
Carbon steel tube support plate (Item 3.1.1-20)	Ligament cracking due to corrosion	Plant specific		Not applicable, PWR only
Steam generator feedwater inlet ring and supports (Item 3.1.1-21)	Loss of material due to flow-corrosion	Combustion engineering (CE) steam generator feedwater ring inspection		Not applicable, PWR only
Reactor vessel closure studs and stud assembly (Item 3.1.1-22)	Crack initiation and growth due to SCC and/or IGSCC	Reactor head closure studs	Reactor Head Closure Studs Program (B.2.3)	Consistent with GALL, which recommends no further evaluation (Section 3.1.2.1)
CASS pump casing and valve body (Item 3.1.1-23)	Loss of fracture toughness due to thermal aging embrittlement	Inservice inspection	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program (B.2.1)	Consistent with GALL, which recommends no further evaluation (Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
CASS piping (Item 3.1.1-24)	Loss of fracture toughness due to thermal aging embrittlement	Thermal aging embrittlement of CASS		Not applicable (See Section 3.1.2.1)
BWR piping and fittings; steam generator components (Item 3.1.1-25)	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	Flow-Accelerated Corrosion Program (B.2.5)	Consistent with GALL, which recommends no further evaluation (Section 3.1.2.1)
RCPB valve closure bolting, manway and holding bolting, and closure bolting in high pressure and high temperature systems (Item 3.1.1-26)	Loss of material due to wear; loss of preload due to stress relaxation; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	Reactor Head Closure Studs Program (B.2.3), Bolting Integrity Program (B.2.6)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.X.X)
Feedwater and control rod drive (CRD) return line nozzles (Item 3.1.1-27)	Crack initiation and growth due to cyclic loading	Feedwater nozzle; CRD return line nozzle	Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Consistent with GALL, which recommends no further evaluation (Section 3.1.2.2)
Vessel shell attachment welds (Item 3.1.1-28)	Crack initiation and growth due to SCC, IGSCC	BWR vessel ID attachment welds; water chemistry	Water Chemistry Program (B.2.2), Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Not consistent with GALL (See Section 3.1.2.2)
Nozzle safe ends, recirculation pump casing, connected systems piping and fittings, body and bonnet of valves (Item 3.1.1-29)	Crack initiation and growth due to SCC, IGSCC	BWR stress corrosion cracking; water chemistry	Water Chemistry Program (B.2.2), BWR Stress Corrosion Cracking Program (B.2.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.2)
Penetrations (Item 3.1.1-30)	Crack initiation and growth due to SCC, IGSCC, cyclic loading	BWR penetrations; water chemistry	Water Chemistry Program (B.2.2), Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Not consistent with GALL (See Section 3.1.2.2)
Core shroud and core plate, support structure, top guide, core spray lines and spargers, jet pump assemblies, CRD housing, nuclear instrumentation guide tubes (Item 3.1.1-31)	Crack initiation and growth due to SCC, IGSCC, IASCC	BWR vessel internals; water chemistry	Water Chemistry Program (B.2.2), Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Core shroud and core plate access hole cover (welded and mechanical covers) (Item 3.1.1-32)	Crack initiation and growth due to SCC, IGSCC, IASCC	ASME Section XI inservice inspection; water chemistry	Water Chemistry Program (B.2.2), Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Not consistent with GALL (See Section 3.1.2.2)
Jet pump assembly castings; orificed fuel support (Item 3.1.1-33)	Loss of fracture toughness due to thermal aging and neutron embrittlement	Thermal aging and neutron irradiation embrittlement	Reactor Vessel and Internals Structural Integrity Program (B.2.28)	Not consistent with GALL (See Section 3.1.2.2)
Unclad top head and nozzles (Item 3.1.1-34)	Loss of material due to general, pitting, and crevice corrosion	Inservice inspection; water chemistry	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program (B.2.1); Water Chemistry Program (B.2.2)	Consistent with GALL, which recommends no further evaluation (See Section 3.1.2.2)
CRD nozzle (Item 3.1.1-35)	Crack initiation and growth due to PWSCC	Ni-alloy nozzles and penetrations; water chemistry		Not applicable, PWR only
Reactor vessel nozzles safe ends and CRD housing; RCS components (except CASS and bolting) (Item 3.1.1-36)	Crack initiation and growth due to cyclic loading, and/or SCC and PWSCC	Inservice inspection; water chemistry		Not applicable, PWR only
Reactor vessel internals CASS components (Item 3.1.1-37)	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement, and void swelling	Thermal aging and neutron irradiation embrittlement		Not applicable, PWR only
External surfaces of carbon steel components in RCS pressure boundary (Item 3.1.1-38)	Loss of material due to boric acid corrosion	Boric acid corrosion		Not applicable, PWR only
Steam generator secondary manways and handholds (Item 3.1.1-39)	Loss of material due to erosion	Inservice inspection		Not applicable, PWR only
Reactor internals, reactor vessel closure studs, and core support pads (Item 3.1.1-40)	Loss of material due to wear	Inservice inspection		Not applicable, PWR only

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Pressurizer integral support (Item 3.1.1-41)	Crack initiation and growth due to cyclic loading	Inservice inspection		Not applicable, PWR only
Upper and lower internals assembly (Westinghouse) (Item 3.1.1-42)	Loss of preload due to stress relaxation	Inservice inspection; loose part and/or neutron noise monitoring		Not applicable, PWR only
Reactor vessel internals in fuel zone region (except Westinghouse and B&W baffle bolts) (Item 3.1.1-43)	Loss of fracture toughness due to neutron irradiation embrittlement, and void swelling	PWR vessel internals; water chemistry		Not applicable, PWR only
Steam generator upper and lower heads; tubesheets; primary nozzles and safe ends (Item 3.1.1-44)	Crack initiation and growth due to SCC, PWSCC, IASCC	Inservice inspection; water chemistry		Not applicable, PWR only
Vessel internals (except B&W and Westinghouse baffle former bolts) (Item 3.1.1-45)	Crack initiation and growth due to SCC and IASCC	PWR vessel internals; water chemistry		Not applicable, PWR only
Reactor internals (B&W screws and bolts) (Item 3.1.1-46)	Loss of preload due to stress relaxation	Inservice inspection; loose part monitoring		Not applicable, PWR only
Reactor vessel closure studs and stud assembly (Item 3.1.1-47)	Loss of material due to wear	Reactor head closure studs		Not applicable, PWR only
Reactor internals (Westinghouse upper and lower internal assemblies; CE bolts and tie rods) (Item 3.1.1-48)	Loss of preload due to stress relaxation	Inservice inspection; loose part monitoring		Not applicable, PWR only

The staff's review of the BSEP component groups followed one of three approaches depending on the group's consistency with the GALL Report. SER Section 3.1.2.1 discusses the staff's review and documentation of the AMR results for components in the reactor vessel, internals, and RCS that the applicant indicated are consistent with the GALL Report and do not require further evaluation; SER Section 3.1.2.2 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended; and, SER Section 3.1.2.3 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of BSEP AMPs that are credited to manage or monitor aging effects of the reactor vessel, internals, and RCS components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.1.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the reactor vessel, internals, and RCS components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Reactor Head Closure Studs Program
- Reactor Vessel and Internals Structural Integrity Program
- Reactor Vessel Surveillance Program
- Systems Monitoring Program
- Water Chemistry Program
- Closed-Cycle Cooling Water Program
- Bolting Integrity Program

Staff Evaluation. In LRA Tables 3.1.2-1 through 3.1.2-4, the applicant provided a summary of AMRs related to the reactor vessel, internals, and RCS components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff's review of the LRA, as documented in the Audit and Review Report, dated June 21, 2005, did not repeat matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

In LRA Section 3.1, the applicant provided the results of its AMRs for the reactor vessel, internals, and RCS.

In LRA Tables 3.1.2-1 through 3.1.2-5, the applicant provided a summary of the AMR results for component types associated with (1) reactor vessel and internals; (2) neutron monitoring system; (3) reactor manual control system; (4) control rod drive hydraulic system; and, (5) reactor coolant recirculation system. The summary information for each component type included: intended function; material; environment; aging effect requiring management; AMPs; the GALL Report Volume 2 item; cross reference to the LRA Table 3.1.1 (Table 1); and generic and plant-specific notes related to consistency with the GALL Report.

Also, for each component type in LRA Table 3.1.1, the applicant identified those components that are consistent with the GALL Report for which no further evaluation is required; those components consistent with the GALL Report for which further evaluation is recommended; and components that are not addressed in the GALL Report, together with the basis for their exclusion.

For AMRs that the applicant stated are consistent with the GALL Report and for which no further evaluation is recommended, the staff conducted its audit to determine if the applicant's reference to the GALL Report in the LRA is acceptable.

The staff compared the applicable AMR line items in LRA Tables 3.1.2-1 through 3.1.2-5 to the referenced GALL Report, Volume 2, items to confirm consistency with the GALL Report.

SER Sections 3.1.2.1.1 through 3.1.2.3, below, document the resolution of discrepancies identified by the staff during its audit of those AMRs that the applicant claimed are consistent with the GALL Report and for which no further evaluation is recommended in the GALL Report.

3.1.2.1.1 Crack Initiation and Growth in the Core Shroud and Core Plate (Welded and Mechanical Covers) in the Reactor Vessel

LRA Table 3.1.2-1 includes AMR results line items for core shroud and core plate access hole covers (AHCs) that are constructed of nickel-based alloys and exposed to treated water on their external surface. The Reactor Vessel and Internals Structural Integrity Program and Water Chemistry Program are specified to manage cracking due to SCC for these components; however, GALL Report line item IV.B1.1-d recommends ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for Class 1 components, along with the Water Chemistry Program to manage this aging effect. In addition, since cracking initiated in crevice regions of AHC welds is not amenable to visual inspection under the ASME Section XI inservice inspection program, an augmented inspection, including UT or other demonstrated acceptable inspection, is also recommended in the GALL Report for AHC welds containing crevices. This augmented inspection is not addressed in the applicant's AMR.

The staff requested that the applicant clarify the discrepancy between the AMPs specified in the LRA and the AMPs recommended in the GALL Report for managing crack initiation due to SCC for the core shroud and core plate access hole covers and to state why the augmented inspection program for the AHCs, which covers welded components, is not discussed in the LRA. As documented in the BSEP Audit and Review Report, the applicant stated that the ASME Section XI inservice inspection requirements are captured as part of the Reactor Vessel and Internals Structural Integrity Program in LRA Section B.2.28.

In addition, the applicant stated that the procedures that implement the Reactor Vessel and Internals Structural Integrity Program include enhanced inspections of the AHCs. Specifically, the inspections performed may be either a UT or an EVT-1 (enhanced VT-1). However, EVT-1 is not consistent with the discussion in the AMR line for core shroud/core plate AHC, which states that the examination should be a UT examination method. This issue is investigated in RAI B.2.28-6, Parts A and B, and is dispositioned by staff in SER Section 3.0.3.3.1.

On the basis of its review, with the exception of RAI B.2.28-6, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.1.2.1.2 Reduction of Fracture Toughness for Cast Austenitic Stainless Steel Piping in the Reactor Coolant Recirculation System

LRA Table 3.1.2-5 includes an AMR line item for piping and fittings in the reactor coolant recirculation system that are constructed of CASS and exposed to treated water. The One-Time

Inspection Program is specified to manage reduction of fracture toughness due to thermal aging embrittlement for these components; however, GALL Report line item IV.C1.1-g recommends the Thermal Aging Embrittlement of CASS Program (GALL AMP XI.M12) to manage this aging effect. LRA Table 3.1.1, Item 3.1.1, is also referenced for this AMR, which states that BSEP does not have CASS piping in the RCS, except for the main steam line flow limiters and the reactor coolant recirculation pump discharge flow elements. These components are assumed to be susceptible to thermal embrittlement; however, an AMP may not be needed based on a formal screening for susceptibility. The description of the One-Time Inspection Program in LRA Section B.2.15 also states that managing reduction of fracture toughness due to thermal aging embrittlement for CASS components may not be necessary based on the outcome of a review of material susceptibility.

The staff noted that the LRA does not address when this screening will be completed. During the audit, the staff asked the applicant to provide clarification as to when the screening of CASS components for material susceptibility to thermal embrittlement will be completed, and how the One-Time Inspection Program compares to GALL AMP XI.M12, which is recommended for managing reduction of fracture toughness for susceptible CASS components. Also, the applicant was asked to explain why the One-Time Inspection Program is used to manage thermal embrittlement in CASS components instead of the Reactor Vessel and Internals Structural Integrity Program, since LRA Table B-1, "Correlation of the NUREG-1801and BSEP Aging Management Programs," indicates that GALL AMP XI.M12 is part of the RV&ISIP.

As documented in the staff's Audit and Review Report, the applicant stated that the initial screening for material susceptibility to thermal embrittlement of the main steam line flow limiters and reactor coolant recirculation pump discharge flow elements has been completed. The staff determined that these components are not susceptible to reduction of fracture toughness due to thermal aging embrittlement. Therefore, the affected AMR results will be updated to reflect this, and the One-Time Inspection Program will be updated to remove these components from the program.

The staff reviewed the applicant's response and determined that it is acceptable on the basis that the applicant completed its screening for material susceptibility and determined that there are no CASS piping and fittings that are susceptible to thermal embrittlement. Therefore, the aging effect identified in the AMR for recirculation system piping and fittings is no longer applicable as stated by the applicant, in its letter dated March 14, 2005, (ML050810493), The applicant will delete the reference in the AMR table to update the affected AMRs to reflect the results of the screening for susceptibility of CASS components to thermal embrittlement. and to update the One-Time Inspection Program to remove these components.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report..

3.1.2.1.3 Loss of Material, Loss of Preload, and Crack Initiation and Growth of Pressure-Retaining Bolting in High Pressure and High Temperature Systems

LRA Table 3.1.2-5 includes AMR line items for recirculation pump closure bolting that is constructed of low-alloy steel and exposed to indoor air. The Bolting Integrity Program is specified to manage loss of material and loss of pre-load for these components. GALL Report line items IV.C1.2-d and IV.C1.2-e, respectively, are referenced, and both recommend the Bolting

Integrity Program to manage this aging effect. Generic Note B is listed for these AMRs indicating consistency with the GALL Report, with the exception that the AMP takes exceptions to the AMP recommended in the GALL Report.

The staff compared the Bolting Integrity Program to the AMP recommended in the GALL Report and determined that the exceptions stated for the BSEP AMP effectively remove the ASME inservice inspection requirements from this AMP. Therefore, the staff reviewed and determined that the Bolting Integrity Program alone is not sufficient to manage aging for the AMRs in question since it does not include the ASME ISI requirements.

As part of its audit of the AMRs for the ESF systems in delineated LRA Section 3.2, the staff asked for clarification on the Bolting Integrity Program as it relates to pressure-retaining bolting. In its response, as documented in the Audit and Review Report, the applicant committed, by letter dated March 14, 2005, (ML050810493), to revising the Bolting Integrity Program to include the ASME inservice inspection requirements, along with monitoring and trending activities for pressure-retaining bolting (see Commitment Item #3). The revised AMP that includes the ASME ISI requirements resolves the discrepancy noted above.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Review Results For Which Further Evaluation is Recommended By the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.1.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the reactor vessel, internals, and RCS components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage (BWR/PWR)
- loss of material due to crevice and pitting corrosion (BWR/PWR)
- loss of fracture toughness due to neutron irradiation embrittlement (BWR/PWR)
- crack initiation and growth due to thermal and mechanical loading or stress corrosion cracking (BWR/PWR)

Staff Evaluation. For some line items assigned to the staff in LRA Tables 3.1.2-1 through 3.1.2-5, the GALL Report recommends further evaluation. When further evaluation is recommended, the staff reviewed these further evaluations provided in LRA Section 3.1.2.2 against the criteria provided in the SRP-LR Section 3.1.3.2. The staff's assessments of these evaluations is documented in this section. These assessments are applicable to each Table 2 line item in Section 3.1 that cites the item in Table 1.

3.1.2.2.1 Cumulative Fatigue Damage (BWR/PWR)

Cumulative fatigue is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is performed and addressed in SER Section 4.3.

3.1.2.2.2 Loss of Material Due to Crevice and Pitting Corrosion (BWR/PWR)

Steam Generator Shell Crevice and Pitting Corrosion (LRA Section 3.1.2.2.2.1). Loss of material for a steam generator shell assembly is applicable to PWRs only.

Isolation Condenser Crevice and Pitting Corrosion (LRA Section 3.1.2.2.2.2). BSEP does not have an isolation condenser.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement (BWR/PWR)

Neutron Irradiation Embrittlement TLAA (LRA Section 3.1.2.2.3.1). Neutron irradiation embrittlement is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in SER Section 4.2.

Reactor Vessel Embrittlement (LRA Section 3.1.2.2.3.2). In the LRA Section 3.1.2.2.3.2, the applicant stated that loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel. A materials surveillance program monitors neutron irradiation embrittlement of the reactor vessel. The BSEP Reactor Vessel Surveillance Program, and the results of its evaluation for license renewal, are presented in Section 3.0.3.2.10.

Reactor vessel embrittlement is reviewed and addressed in SER Section 3.0.3.3.1.

3.1.2.2.4 Crack Initiation and Growth Due to Thermal and Mechanical Loading or Stress Corrosion Cracking (BWR/PWR)

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

Small-Bore Reactor Coolant System and Connected System Piping (LRA Section 3.1.2.2.4.1). The staff reviewed LRA Section 3.1.2.2.4.1 against the criteria in SRP-LR Section 3.1.2.2.4.

As documented in the staff's BSEP Audit and Review Report, in LRA Section 3.1.2.2.4.1, the applicant requested and received approval from the NRC to use RI-ISI in 2001. In support of the request, evaluations of degradation mechanisms were performed, and they demonstrated that no locations had a high failure potential on small bore pipe due to TASCS and TTs. The RI-ISI evaluations considered lines greater than 1-inch in diameter. For lines 1-inch and smaller, cracking due to thermal loadings was evaluated and dispositioned as not applicable. Cracking due to mechanical loadings was evaluated by a review of plant-specific operating experience; no relevant operating experience was found. The risk associated with cracking due to SSC of these lines is bounded by those components selected for inservice inspection as part of RI-ISI program. Therefore, the current inspection methods, as detailed in the ASME Section XI, Subsection IWB, IWC and IWD Program, supplemented by the Water Chemistry Program, will manage cracking of small bore piping systems.

The staff noted that an RI-ISI evaluation is not an acceptable technical basis for excluding small-bore Class 1 piping from one-time inspection, as recommended by the SRP-LR. Staff approval of an RI-ISI program is only for the current inspection interval and does not cover the extended period of operation. Therefore, during its review of the One-Time Inspection Program, the staff rejected the applicant's technical basis for not including inspections of small bore Class 1 piping in the scope of the BSEP AMP.

Consequently, the applicant stated, as documented in the BSEP Audit and Review Report, that it will revise the One-Time Inspection Program to be consistent with GALL Report AMP XI.M32. On the basis of its review, the staff found the One-Time Inspection Program to be acceptable.

Additionally, as requested by staff and documented in the Audit and Review Report, the applicant identified, and committed, by letter dated, May 4, 2005, (ML051330020), to make all required revisions to the LRA in order to include small bore Class 1 piping in the scope of the One-Time Inspection Program (see Commitment Item #11). The LRA will no longer reference or credit RI-ISI for aging management. BSEP credits the ASME Section XI, Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program for aging management, and will use the One-Time Inspection Program for verification of program effectiveness, consistent with the recommendations of the GALL Report.

Based on the applicant's new commitment to include small bore Class 1 piping in the scope of the One-Time Inspection Program and to revise the LRA as identified above and in the Audit and Review Report, the staff reviewed the applicant's commitment and determined that the applicant has met the criteria of SRP-LR Section 3.1.2.2.4 for further evaluation. For those AMRs whose further evaluation is provided in LRA Section 3.1.2.2.4.1, the staff concluded that the AMRs are consistent with the GALL Report and are acceptable.

<u>Reactor Vessel Flange Leak Detection Line and Jet Pump Sensing Line</u>. In LRA Section 3.1.2.2.4.2, as discussed in the Audit and Review Report, the applicant stated that the reactor vessel flange leak detection line is a Class 2 line that is normally dry. The BSEP AMR methodology assumed that this stainless steel line is exposed to treated water and, therefore, is susceptible to SCC. This aging effect will be managed with a combination of the Water Chemistry Program and the One-Time Inspection Program.

The staff reviewed LRA Section 3.1.2.2.4.2 and determined that cracking due to SCC in the reactor vessel flange leak detection line is possible since the stainless steel lines are exposed to treated water at high temperature. However, these lines normally remain dry during reactor operation, unless a leak develops between the closure head and vessel head flanges. The Water Chemistry Program would minimize susceptibility to SCC if a leak develops in the system. A one-time inspection of this small bore piping would provide reasonable assurance that cracking due to SCC is not occurring. If degradation is detected, then appropriate action would be taken to mitigate the aging effect. Therefore, the staff determined that the applicant's approach to manage cracking due to SCC in vessel flange leak detection lines is acceptable on the basis that it provides reasonable assurance that the effects of aging will be adequately managed.

In LRA Section 3.1.2.2.4.2, the applicant also stated that the jet pump sensing lines were evaluated for flow-induced vibration as part of the extended power uprate (EPU). This evaluation determined that the sensing line natural frequency of interest is well separated from the vane passing frequency of the recirculation pumps at EPU conditions. The failure of a sensing line at any location would be detected during jet pump surveillance, which is performed at least daily. Failure of a sensing line does not affect the pressure measurement taken for post-accident water level monitoring. If one or more jet pumps are inoperable, the plant must be brought to mode 3 within 12 hours. Therefore, the applicant claims that no AMP is required.

As documented in the Audit and Review Report, the staff agreed with the applicant's claim that there is no resonance between the vane passing frequency of the recirculation pump and the natural frequency of the jet pump sensing lines.

The staff noted that LRA Table 2.3.1-1, "Component/Commodity Groups Requiring Aging Management Review and Their Intended Functions: Reactor Vessel and Internals," identifies M4 (provides structural support/seismic integrity) as the only intended function for these lines. The intended function M1 (provides pressure-retaining boundary), which the staff expected for the portion of the jet pump sensing line external to the reactor vessel, was not identified. During the audit, the staff requested that the applicant provide clarification on how aging management of the jet pump sensing line external to the reactor vessel is addressed.

In its response, the applicant stated that the jet pump sensing lines that are external to the reactor vessel are evaluated as part of the component/commodity group "piping and fittings (small bore piping less than NPS 4)." This component/commodity group is evaluated in LRA Table 3.1.2-1. The applicant also noted that the AMR for this line item will be revised to add the One-Time Inspection Program.

The staff reviewed the applicant's response and determined that it was acceptable on the basis that the portion of the jet pump sensing line external to the reactor vessel is included in the commodity group for small bore piping, which is addressed in LRA Table 3.1.2-1. The portion of the jet pump sensing line internal to the reactor vessel is submerged in reactor coolant and its failure would not have any consequence in terms of a reactor coolant leak. Therefore, the portion of the jet pump sensing line internal to the reactor vessel does not have an intended pressure-retaining boundary function, and the applicant's identification of the structural support/seismic integrity intended function (M4 in LRA Table 2.0-1), is appropriate.

The staff reviewed the applicant's response and determined that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.4 for further evaluation. For those AMRs whose further evaluation is provided in LRA Section 3.1.2.2.4.2, the staff concluded that the applicant is consistent with the GALL Report and the AMRs are acceptable.

<u>Isolation Condenser Components</u>. LRA Section 3.1.2.2.4.3 states that BSEP does not have an isolation condenser.

On the basis that BSEP does not have any components from this group, the staff agreed with the applicant's determination that this aging effect is not applicable.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that: (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent; and, (2) the applicant adequately addressed the issues that were further evaluated. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3 AMR Results That Are Not Consistent with the GALL Report or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.1.2-1 through 3.1.2-5, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.1.2-1 through 3.1.2-5, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line-item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line-item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line-item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line-item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.1.2.3.1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals – Table 3.1.2-1

The staff reviewed LRA Table 3.1.2-1, which summarizes the results of AMR evaluations for the reactor vessel and internals component groups.

Reactor Vessel Components. The RVs are located within the drywell structures. The RVs are fabricated from low-alloy steel plates and welds and are clad internally with stainless steel. The RV shells are fabricated from four shell courses: (1) upper RV shell, (2) intermediate RV shell, (3) intermediate beltline RV shell, and (4) lower RV shell. Two of these RV shell courses, the intermediate beltline RV shell and lower RV shell, are located in the beltline region of the RV that immediately surrounds the RV core. The beltline region of the RV is the region of the RV that receives the greatest amount of irradiation by high-energy neutrons (E$1.0 MeV). The RV top head flanges are bolted to the RV shell flanges using studs and nuts.

The applicant's plant-specific AMRs for the RV components are given in LRA Table 3.1.2-1. The specific RV components that are within the scope of LRA Table 3.1.2-1 include:

- RV top head assembly (including the RV top head enclosure, the RV top head flange, the RV top head nozzles, and the RV top head closure studs and nuts)
- RV shell courses (including the upper RV shell course and the RV flange, intermediate RV shell course, lower intermediate beltline RV shell course, and lower RV shell course; the RV welds, and the RV attachment welds)
- RV nozzles (including main steam nozzles, feedwater nozzles and their thermal sleeves, CRD return nozzles, recirculation inlet and outlet nozzles, low pressure core spray nozzles and their thermal sleeves, and shell flange nozzles).
- RV bottom heads and the RV support skirt attachment welds
- RV drain line penetrations
- RV internior attachment welds

The applicant identified that the materials of fabrication for the RV components include carbon steel, low-alloy steel, stainless steel, and nickel-based alloys. The applicant identified that the applicable environments for the RV components include the containment and indoor air environments and the treated water (including steam) environment.

The RV interior attachment welds are managed by the applicant's RV&ISIP and are, therefore, treated in this SER as RV internal components. The staff's assessments of the plant-specific AMRs for RV interior attachment welds are given in SER Section 3.1.2.3.1, "RV Internal Components."

The applicant also credited the RV&ISIP with the management of cracking due to cyclical loading in the low-alloy steel RV feedwater nozzles and low-alloy RV drain line penetrations. The applicant's AMR for assessing cracking due to cyclical loading of the low-alloy steel RV feedwater nozzles has been identified by the applicant as an AMR that is consistent with GALL Report, Volume 2, as modified by the applicant in Footnote E of LRA Tables 3.1.2-1 through Table 3.1.2-4, in which the applicant credits an alternative program to that recommended in the GALL Report. The staff evaluated the AMR on cracking due to cyclical loading of the RV feedwater nozzles in SER Section 3.1.2.1. The applicant's AMR for assessing cracking due to cyclical loading of the low-alloy steel RV drain line penetrations has been identified by the applicant as a plant-specific AMR. The staff deferred its assessment of the AMR on cracking due to cyclical loading of the RV drain line penetrations to SER Section 3.1.2.3.1, "RV Internal Components," because the applicant opted to credit the RV&ISIP with management of this aging effect.

Management of Specific Aging Effects Using Time Limited Aging Analyses (TLAAs) - Crack Initiation Due to Thermal Fatigue

<u>Identification of Aging Effects</u> - The applicant identified cracking due to thermal fatigue as an applicable aging effect for all RV components and their supports. This is consistent with the SRP-LR and is, therefore, acceptable. In addition, although not requested to do so, the applicant provided, in its response to RAI No. 3.1.2.3.1.1-1, Part B, dated June14, 2005, the following supplemental information:

Part B: Reduction of fracture toughness due to neutron irradiation embrittlement is an applicable aging effect for all the components in the commodity groups described in Part A.

Note that the AMR line items for cracking due to thermal fatigue in LRA Tables 3.1.2-1, 3.2.2-1, 3.3.2-1, and 3.4.2-1 refer to "Table 1" items 3.1.1-01, 3.2.1-01, 3.3.1-01, and 3.4.1-01, respectively. This "Table 1" item addresses cumulative fatigue damage. Cumulative fatigue damage is addressed topically in Section 4.3 of the LRA. Cracking due to thermal fatigue is the aging effect/mechanism combination that is addressed by the time-limited aging analyses (TLAAs) when calculating cumulative fatigue damage.

The applicant’s supplemental response to RAI 3.1.2.3.1.1-1, Part B, clarified that the phrase “cracking due to thermal fatigue,” as defined in the applicable AMR line items for “Table 2” in LRA Sections 3.1, 3.2, 3.3, 3.4, and 3.5, corresponds to the definition “cumulative fatigue damage” in the applicant AMR line items for “Table 1" in LRA Sections 3.1, 3.2, 3.3, 3.4, and 3.5. The applicant changed the terminology because it recognized that 10 CFR 54.21(a) requires that aging effects be managed for the period of extended operation and because the term “cumulative fatigue damage” referred to a parameter that is used to assess the aging effect of cracking due to thermal fatigue and was not referring to the aging effect itself. Based on this assessment, the change in the terminology from “cumulative fatigue damage” in the “Table 1” to “cracking due to thermal fatigue” in the “Table 2” was done to satisfy the provision and criteria of 10 CFR 54.21(a). This meets the provisions in SRP-LR Sections 3.1, 3.2, 3.3, 3.4, and 3.5 for assessing cracking due to thermal fatigue/cumulative fatigue damage in ASME Code Class 1, 2, and 3 components and any applicable NSR components that are required to have thermal fatigue assessments for license renewal and, therefore, is acceptable. Refer to SER Section 4.3 for the staff’s assessment of those plant components that are required to have thermal fatigue analyses for the LRA.

Aging Management - The applicant proposed to manage cracking due to thermal fatigue using the TLAA for assessing thermal fatigue/cumulative fatigue damage of ASME Code Class 1 components, which is given in LRA Section 4.3. This is consistent with the SRP-LR and is, therefore, acceptable. The staff evaluated the applicant’s TLAA on thermal fatigue of ASME Code Class 1 components in SER Section 4.3.

Evaluation - Reduction of Fracture Toughness Properties in the RV Shell Courses Due to Neutron Irradiation Embrittlement

Identification of Aging Effects - The shells and heads of the RVs are fabricated from low-alloy steel plates and weld materials. The applicant identified reduction of fracture toughness as a result of neutron irradiation embrittlement as an applicable aging effect for those low-alloy steel plates and welds that are used to fabricate the intermediate beltline RV shell and lower RV shell courses of the RVs.

Considerable fracture toughness data compiled by the Oak Ridge National Laboratory demonstrated that prolonged irradiation of RV low-alloy steel materials by high-energy neutrons (E $1.0 MeV) reduces the fracture toughness properties of the materials over time. The NRC established a threshold in 10 CFR Part 50, Appendix H, of 1×10^{17} neutrons per square centimeter (n/cm^2, E $1.0 MeV) for neutron irradiation embrittlement of low-alloy steel materials in the RCPB. Neutron irradiation embrittlement/reduction of fracture toughness properties is a concern for only those low-alloy steel RV shell and weld materials located in the beltline region of the RVs, where the 54 EFPY neutron fluence values have been projected to exceed the NRC's threshold for neutron irradiation.

In RAI 3.1.2.3.1.1-1, Part A, by letter dated May 18, 2005, the staff noted that the applicant appeared to have used two different terminologies for the RV intermediate beltline shell in the LRA. In LRA Table 3.1.2-1, the applicant defined the beltline shell course as the "RV Shell (intermediate beltline shell)." In contrast, in LRA Tables 4.2.5 and 4.2.6, which are associated with TLAAs in LRA Section 4.2, "Reactor Vessel Neutron Embrittlement," the applicant refers to two RV shell courses in the beltline region of the RVs: (1) the "RV Lower Intermediate Shell" and (2) the "RV Lower Shell." The staff also noted that reduction of fracture toughness due to neutron irradiation embrittlement was not identified in Table 3.1.2-1 as an applicable aging effect for the "RV Shell (Lower Shell)" plates, even though it had been identified and analyzed as an aging effect in LRA Tables 4.2-5 and 4.2-6. Therefore, the staff inquired about these inconsistencies in the application.

In its response, by letter dated June 14, 2005, the applicant stated:

> Part A: The terminology used in LRA Tables 4.2-5 and 4.2-6 is consistent with the submittals BSEP has previously made in relation to Generic Letter 92-01, "Reactor Vessel Structural Integrity." The terminology used in LRA Section 3.1 is in the form of "commodity groups."
>
> The "Vessel Shell (Intermediate Beltline Shell)" is a commodity group name derived from NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." It is not meant to describe particular shell courses of the reactor vessel (RV). However, this commodity group does include the following items from Tables 4.2-5 and 4.2-6:
>
> - Plates: Lower Shell,
> - Plates: Lower Intermediate Shell, and
> - Nozzles: N16A, N16B (i.e., forgings).
>
> The "Vessel Shell (Beltline Welds)" is another commodity group name derived from GALL. This commodity group does include the following items from Tables 4.2-5 and 4.2-6:
>
> - Welds: Vertical (i.e., G1, G2, F1, and F2) and
> - Welds: Girth (i.e., EF and FG).

The applicant's response to RAI 3.1.2.3.1.1-1, Part A, clarified that the AMR line item on reduction of fracture toughness properties for the "intermediate beltline shell" course covers the following components: lower shell plates, lower intermediate shell plates, N16-A and -B instrumentation nozzle forgings, and associated welds. This is consistent with components analyzed in Section 4.2 of the application and resolves the apparent discrepancy that was thought to exist between the AMR lines item and the TLAA analyses. The response also agreed that reduction of fracture toughness is an applicable aging effect for all of these components. Therefore, the applicant's response to RAI 3.1.2.3.1.1-1, Part A, is acceptable because it clarified that the RV shell plate and weld components in the applicant's AMR analysis is consistent with those analyzed for neutron irradiation embrittlement in Chapter 4.2 of the application.

Based on this assessment, the staff concluded that the applicant performed an acceptable identification of those RV beltline plate and weld components that are subject to neutron irradiation embrittlement/reduction of fracture toughness properties. Therefore, the staff's concern described in RAI 3.1.2.3.1.1-1 is resolved.

Aging Management - The applicant proposed to manage this reduction of fracture toughness using a number of TLAAs on neutron irradiation embrittlement of these components, which are defined and discussed in LRA Sections 4.2.1, 4.2.2, 4.2.3, 4.2.4, 4.2.5, 4.2.6, 4.2.7, 4.2.8, and 4.2.9 and in the applicant's response and supplemental response to RAI 4.2-2, which provided a supplemental TLAA on the RV reflood thermal shock analysis. This is consistent with the SRP-LR and acceptable. The staff evaluated these TLAAs in SER Sections 4.2.1, 4.2.2, 4.2.3, 4.2.4, 4.2.5, 4.2.6, 4.2.7, 4.2.8, and 4.2.9. SER Section 4.2.10, added in response to RAI 4.2-2, dated April 8, 2005, provides the staff's basis for accepting the TLAA on RV Reflood Thermal Shock Analysis under the acceptance criterion of 10 CFR 54.21(c)(1)(ii).

RV Components that are Exposed to the Indoor Air/Containment Air Environments

Identification of Aging Effects - With the exception of the RV top head studs and nuts, the applicant did not identify any AERMs for the RV components that are exposed externally to the indoor air environment, including those RV components that are fabricated from either carbon steel, low-alloy steel, stainless steel, or nickel-based alloy materials. The applicant's external indoor air environment for the RV is subdivided into one of two types of atmospheric environments: (1) indoor air during refueling outages or (2) containment air during plant operations. In LRA Table 3.0-2, the applicant provided the following definition of the indoor air environment:

> Atmospheric air, specific temperature range/humidity dependent upon building/room/area. Typically, temperature is 104 EF maximum in most areas and radiation dose levels are negligible. Potentially wetted.

The applicant also provides the following definition of the containment air environment:

> Nitrogen atmosphere (atmospheric air during refueling outages). Specific temperature range dependent upon area. Bulk average temperature 150 EF maximum. Relative humidity 40 - 90%. Pressure +2.5/-0.5 psig. Gamma radiation dose level: maximum 60-year total integrated dose (TID) 1.25×10^8 rad gamma (1.32×10^{10} rad gamma (54 EFPY) at inside face of sacrificial shield wall). Maximum neutron fluence (54 EFPY) of 4.03×10^{17} n/cm^2 (E>1 Mev) inside face of the sacrificial shield wall.

The predominant external environment for the RV components is containment air because the indoor air environment only occurs infrequently: during scheduled refueling outages for the plants, normally 6 to12 percent of the time, depending on the length of the refueling outages.

The applicant included plant-specific Footnote 101 in LRA Table 3.1.2-1 through 3.1.2-4, as its basis for establishing its position that cracking or loss of material would not occur in stainless steel or nickel-based alloy RV components under the indoor/containment air environments. In this footnote, the applicant stated that stainless steel and nickel-based alloy components do not have any applicable aging effects in non-aggressive indoor air environments (i.e., indoor air environments that do not contain significant aggressive chemical species). The staff agreed with this assessment because stainless steel and nickel-based alloy materials are generally designed to be corrosion resistant in indoor air environments that do not contain aggressive chemical species (e.g., halides or sulfates) that, if present, might otherwise lead to corrosion-induced loss of material or cracking in the materials. Since the indoor/containment air environments do not normally contain aggressive chemical species, the staff agreed that aging effects do not need to be identified for the stainless steel and nickel-based alloy RV components that are exposed to indoor/containment air environments and concluded that the applicant’s assessment is acceptable.

The applicant included plant-specific Footnote 109 in LRA Table 3.1.2-1 through 3.1.2-4A as its basis for establishing its position that loss of material would not occur in carbon steel or low-alloy steel RV components under the indoor/containment air environments. In this footnote, the applicant stated that general corrosion is not a concern for the carbon steel/low-alloy steel RV components that are exposed to these environments because the components operate at temperatures equal to or above 212EF. The maximum bulk average temperature of the indoor/containment air environments is identified in the application as 150EF. Since the carbon steel/low-alloy steel RV components operate at temperatures above the maximum bulk average temperature for the indoor/containment air environments, the staff concluded that loss of material/general corrosion induced by the precipitation of water will not be an issue for the carbon steel/low-alloy steel RV components that are exposed to these environments. Furthermore, industry operating experience has not yet identified that SCC is an AERM for carbon steel/low-alloy steel components that are exposed to indoor air environments, in the absence of aggressive chemical species. Since the indoor/containment air environments do not normally contain aggressive chemical species, the staff agreed that SCC is not an AERM for the carbon steel/low-alloy steel RV components that are exposed to the indoor/containment air environments. Based on this assessment, the staff agreed that neither loss fo material due to general corrosion nor cracking due to SCC need to be identified as AERMs for the carbon steel/low-alloy steel RV components that are exposed to indoor/containment air environments and concluded that the applicant’s assessment is acceptable.

For the RV top head closure studs and nuts, the applicant identified that cracking due to SCC and loss of material due to general corrosion, pitting corrosion, or crevice corrosion were applicable AERMs. The applicant’s identification that SCC is an applicable AERM for these components is consistent with the staff’s AMR in the GALL Report, Volume 2, commodity group line item IV.A1.1-c, and is, therefore, acceptable. GALL Report, Volume 2, does not identify the loss of material due to general corrosion, pitting corrosion, or crevice corrosion as an AERM for RV top head closure studs and nuts. Therefore, the applicant’s identification of loss of material due to general corrosion, pitting corrosion, or crevice corrosion as an applicable AERM for the RV top head closure studs and nuts is conservative relative to the recommended AMRs and AERMs for BWR RV components in the GALL Report, Volume 2, and is acceptable.

Cracking by thermal fatigue is not an issue for the RV components exposed to the indoor/containment air environments, but has been included as a separate AMR entry for the surfaces that are exposed to and loaded under the treated water environment of the reactor coolant. The staff evaluated thermal fatigue of these RV components in SER Section 3.1.2.3.1.

Aging Management Programs - With the exception of the applicant's AMRs for the RV top head closure studs and nuts, the applicant did not identify any AERMs for the RV components that are exposed to the indoor/containment air environments and therefore did not credit any AMPs with aging management. In the Identification of Aging Effects section, the staff provided its bases for concluding that there were not any AERMs for the RV components that are exposed to these environments, with the exception of those for the RV top head closure studs and nuts. Therefore the staff concluded that, with the exception of the AERMs for the RV top head closure studs and nuts, AMPs do not need to be credited for aging management of the RV components that are exposed to indoor/containment air environments.

The applicant credits the Reactor Head Closure Studs Program with aging management of cracking due to SCC in the RV top head closure studs and nuts. Crediting the Reactor Head Closure Studs Program for management of SCC in the RV top head closure studs and nuts is consistent with the staff's recommended AMR in the commodity group line item IV.A1.1-c of GALL, Volume 2, and is, therefore, acceptable. The applicant's Reactor Head Closure Studs Program is an existing AMP that is entirely consistent with GALL AMP XI.M3.

The applicant also credited the Reactor Head Closure Studs Program with the management of loss of material due to general corrosion, pitting corrosion, and crevice corrosion in these components. GALL AMP XI.M3 indicates that the program can be used to detect loss of material due to corrosion or wear in the RV top head closure studs and nuts. There the staff concluded that crediting the Reactor Head Closure Studs Program with management of loss of material in the RV top head closure studs and nuts is also consistent with GALL AMP XI.M3 and is acceptable.

The staff evaluated the ability of the Reactor Head Closure Studs Program to manage cracking and loss of material in the RV top head closure studs and nuts in SER Section 3.0.3.1.

Stainless Steel and Nickel-based Alloy RV Components that are Exposed to the Treated Water (Including Steam) Environment

Identification of Aging Effects - The applicant identified cracking induced by SCC and loss of material due to pitting and crevice corrosion as applicable aging effects for stainless steel and nickel-based alloy RV components exposed internally to the treated water environment. For these components, which include any low-alloy steel RV components clad internally with stainless steel, the treated water environment is reactor coolant or its steam environment. In LRA Table 3.0–1, the applicant provided the following definition of the treated water (including steam) environment:

> Treated water is demineralized water and is the base water for all clean, closed loop systems. Depending on the system, treated water may require additional processing. Treated water can be deaerated, include corrosion inhibitors, biocides, or include a combination of these treatments. Steam generated from treated water is included in this environment category. Typical treated water categories include:
>
> Reactor Water: BSEP water quality parameters for use in the reactor coolant system.

The NRC-approved Topical Report BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," provides the BWRVIP's recommended inspection strategies and flaw evaluation recommendations for BWR RV components. The staff approved this report in an FSER to the BWRVIP, dated October 18, 2001. In this report, the BWRVIP indicates that cracking induced by SCC can be an AERM for stainless steel RV components that are exposed to a BWR reactor coolant environment, including cracking induced by IGSCC and IASCC, which are forms of SCC. BWRVIP-74-A also indicates that SCC can be an AERM for nickel-based alloy RV components that are exposed to a BWR reactor coolant environment, particularly in nickel-based alloy weld filler metals that are fabricated from Alloy 182 or Alloy 82.

The applicant's identification of cracking due to SCC as an AERM for these components under internal exposure to the reactor coolant is consistent with the age-related degradation analysis provided in BWRVIP-74-A and is, therefore, acceptable.

Stainless steels and nickel-based alloys are normally designed to be resistant to general corrosion. In addition, crevice corrosion or pitting corrosion are not expected to be aging mechanisms of concern in the absence of elevated concentrations of dissolved oxygen or dissolved corrosive anionic impurities (such as sulfates or halide impurities) in the reactor coolant. Crevice and pitting corrosion are localized mechanisms that can induce loss of material in components that are located in creviced areas or areas of restricted access, where the exposure of the components to a particular coolant may be prone to stagnant conditions. Neither GALL Report, Volume 2, nor Topical Report BWRVIP-74-A identify that loss of material due to general, pitting, or crevice corrosion is an applicable AERM for the stainless steel and nickel-based alloy RV components (including those low-alloy steel RV components that are designed with internal stainless steel cladding) that are exposed to the reactor coolant (or its steam) environment. In contrast, the applicant identified that loss of material due to pitting and crevice corrosion is an applicable AERM for these components exposed to these environments. The staff concluded that this is acceptable because it is conservative relative to the aging-effect analysis approved in BWRVIP-74-A or the staff's recommended AMR commodity group line items identified in GALL Report, Volume 2, for stainless steel or nickel-based alloy RV components in the reactor coolant pressure boundary.

<u>Aging Management Programs</u> - The applicant credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program with aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in the stainless steel and nickel-based alloy RV components that are exposed to the reactor coolant (or its steam) environment. The applicable ISI examinations for these RV components are required by 10 CFR 50.55a and are defined in applicable inspection categories of Table IWB-2500-1 to Section XI of the ASME Code. Table 4-1 of Topical Report BWRVIP-74-A provides a summary of the ISI inspections that are required for RV components. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the required ISI examinations as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in SER Section 3.0.3.1.

U.S. owners of BWRs implement comprehensive water chemistry control programs to minimize the concentrations of the dissolved oxygen and anionic impurities in the reactor coolant. The applicant's Water Chemistry Program is implemented to satisfy the recommended concentrations for impurities in the EPRI/BWRVIP BWR water chemistry guidelines. Therefore, crediting of the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion is acceptable because implementation of the AMP will be in accordance with the ERPI/BWRVIP water chemistry guidelines and will be used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to these aging mechanisms. The staff evaluated the ability of the Water Chemistry Program to minimize the concentrations of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment in SER Section 3.0.3.1.

Carbon Steel and Low Alloy Steel RV Components that are Exposed to the Treated Water (Including Steam) Environment

Identification of Aging Effects - Not all of the low-alloy steel RV components are clad with austenitic stainless steel. Therefore, the applicant identified loss of material due to general, pitting, and crevice corrosion as an applicable aging effect for those carbon steel/low-alloy steel RV components whose surfaces are exposed internally to the treated water environment. The treated water environment has been described in the previous subsection and, for these RV components, is reactor coolant or its steam.

Topical Report BWRVIP-74-A indicates loss of material due general corrosion as an AERM for carbon steel/low-alloy steel RV components exposed to a BWR reactor coolant environment, even though the BWRVIP states that the amount of general corrosion in the components is expected to be small. The report, as approved by NRC, does not indicate cracking due to SCC (including IASCC or IGSCC) as an applicable aging effect for the carbon steel/low-alloy steel components exposed to the reactor coolant. The applicant identified loss of material due to general corrosion as an AERM for these components and included pitting corrosion and crevice corrosion within the scope of the mechanisms that could lead to this aging effect. This is acceptable to the staff because it adds pitting corrosion and crevice corrosion (in addition to general corrosion) as the mechanisms that can lead to loss of material in these components and is, therefore, more conservative than the corresponding age-related degradation analysis provided in NRC-approved Topical Report BWRVIP-74-A.

The applicant also identified cracking due to cyclical loading as an applicable aging effect for low-alloy steel RV drain line penetrations. The staff opted to evaluate the AMR on cracking due to cyclical loading of the RV drain line penetrations in SER Section 3.1.2.3.1, "RV Internal Components," because the applicant opted to credit the Reactor Vessel and Internals Structural Integrity Program for management of the aging effect.

Aging Management Programs. The applicant credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program with aging management of loss of material due to general, pitting, and crevice corrosion in the carbon steel/low-alloy steel RV components that are exposed to the reactor coolant (or its steam) environment. The applicable ISI examinations for these RV components are required by 10 CFR 50.55a and are defined in applicable ISI categories of Table IWB-2500-1 to Section XI of the ASME Code. Table 4-1 of Topical Report BWRVIP-74-A provides a summary of the inspections that are required for RV components. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for the management of loss of material due to general, pitting, and crevice corrosion is acceptable because the applicant will apply the required ISI examinations as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage this aging effect and mechanisms in SER Section 3.0.3.1.

The applicant credited the Water Chemistry Program for aging management used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to cracking due to SCC and loss of material due to general, pitting and crevice corrosion of low-alloy steel/carbon steel reactor coolant pressure boundary components, including those for the RV. The staff concluded that this is an acceptable AMP for aging management because it will be used to control the concentration of dissolved oxygen and ionic water impurities to acceptable levels, as recommended in the EPRI/BWRVIP water chemistry guidelines. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentration of dissolved oxygen and ionic water impurities in reactor coolant.

Conclusion. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects associated with the RV components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

RV Internal Components. The applicant's plant-specific AMRs for the RV internal components are given in LRA Table 3.1.2-1. The specific RV internal components within the scope of LRA Table 3.1.2-1 include:

- RV internal penetrations (including CRD stub tube penetrations, reactor instrumentation penetrations, jet pump instrumentation penetrations, SLC/core ΔP penetrations, flux monitor penetrations, and RV drain line penetrations).
- RV core shrouds (including the flange, upper, central, and lower shell courses and the core shroud access hole cover)
- Core shroud repair hardware (core shroud repair clamps) and the core shroud support structure
- Core plates, the core plate bolts, and the core plate plugs
- Top guides
- Core spray lines and their subcomponents (including their thermal sleeves, headers, spargers, and sparger nozzles).
- Jet pump assemblies and their subcomponents (including their thermal sleeves, inlet headers, riser brace arms, holddown beams, inlet elbows, mixing assemblies, diffusers, castings, jet pump sensing lines, jet pump holddown beam keepers, lock plates, and bolts)
- Fuel support and CRD assemblies and their subcomponents (including the orificed support plates and the CRD housings)
- RV incore flux instrumentation (including those for the source range monitors and the intermediate range monitors)

- NSR RV internal components (including the steam dryers, core shroud head and separators, feedwater spargers, and the RV surveillance capsule holders)

This section provides the staff's evaluation of the plant-specific AMRs for the RV internal components. The evaluations in this section also include an evaluation of those AMRs for the RV drain line penetration and RV interior attachment welds that credit the RV&ISIP for aging management.

Management of Specific Aging Effects Using Time Limited Aging Analyses (TLAAs) - Crack Initiation Due to Thermal Fatigue

Identification of Aging Effects - The applicant identified cracking due to thermal fatigue as an applicable aging effect for all RV internal components, including the RV penetrations and the RV interior attachment welds, which are RV components within the scope of the RV&ISIP. GALL Report, Volume 2, provides the following AMR commodity group line items on cracking due to thermal fatigue/cumulative fatigue damage of RV internal components:

- AMR Commodity Group IV.A1.5-b, RV penetration components
- AMR Commodity Group IV.B1.1-c, core plate
- AMR Commodity Group IV.B1.2-b, top guide
- AMR Commodity Group IV.B1.3-b, core spray components, including spray lines, spray header, spray rings, and spray nozzles
- AMR Commodity Group IV. B1.4-b. -c. and -d, jet pump assembly components, including castings, sensing lines, mixing assemblies, inlet headers and elbows, hold-down beam, and riser brace arms
- AMR Commodity Group IV.B1.5-b, fuel support - orifice support plate
- AMR Commodity Group IV.B1.6-b, intermediate range monitor and source range monitor dry tubes

The applicant's identification of cracking due to thermal fatigue/cumulative fatigue damage as an applicable aging effect for the RV internal components is consistent and goes beyond the number of AMR commodity group line items for cumulative fatigue damage identified in the SRP-LR and in GALL Report, Volume 2, for RV internal components. The staff concluded that this is acceptable because the AMRs on cracking due to thermal fatigue of the RV internal components is both consistent with and more conservative than those identified in GALL Report, Volume 2.

Aging Management - The applicant credits its TLAA on thermal fatigue of ASME Code Class components with the management of cracking due to thermal fatigue/cumulative fatigue damage in the RV internal components. This TLAA is discussed in LRA Section 4.3. The applicant's determination is consistent with the SRP-LR and is, therefore, acceptable. The staff evaluated the applicant's TLAA on thermal fatigue of ASME Code Class 1 components in SER Section 4.3.

Evaluation - Loss of Preload in the Unit 2 Spring-Loaded Core Plate Plugs

Identification of Aging Effects. In RAI 3.1.2.3.1.2-1, dated May 18, 2005, the staff stated that the applicant identified loss of preload due to stress relaxation as an AERM for spring-loaded, nickel-based alloy core plate plugs at Unit 2. Therefore, the staff requested that the applicant confirm that the applicant's AMR on loss of preload due to stress relaxation of the nickel-based alloy core plate plugs is applicable to the only spring-loaded core plate plugs at Unit 2, and that the core plate plugs at Unit 1 are fabricated from stainless steel and involve a welded design.

In its response, by letter dated June 14, 2005, the applicant stated:

> The Unit 2 plug is constructed from stainless steel for the latch, body, shaft, and pin. The spring for the Unit 2 plug is fabricated from a nickel-based alloy.
>
> The nickel-based alloy material associated with the core plate plugs in Table 3.1.2-1 refers to the Alloy X-750 spring that provides preload to the core plate plug. This mechanical core plate plug design is applicable to BSEP Unit 2 only.
>
> BSEP Unit 1 does not have the mechanical plugs, but has welded plugs fabricated from stainless steel.

Stress relaxation is a time-dependent aging phenomenon in which the imparted stresses or loads used to secure bolted, fastened, keyed, or spring-loaded connections reduces over time and loosens the components. The applicant's response to RAI 3.1.2.2.1.2-1 confirmed that the core plate plugs at Unit 2 are spring loaded. Therefore, the staff concluded that loss of preload due to stress relaxation is an applicable aging effect for the Unit 2 spring-loaded core plate plugs. In contrast, the applicant's response to RAI 3.1.2.2.1.2-1 confirmed that the core plate plugs at Unit 1 are of a welded configuration and not subject to stress relaxation in the manner of the spring-loaded core plate plugs at Unit 2. Based on these analyses, the staff concluded that the applicant's identification of loss of preload/stress relaxation of the Unit 2 spring-loaded core plate plugs is conservative and acceptable, and that stress relaxation at Unit 1 is not an applicable aging effect for the core plate plugs because they are of a welded design; therefore, the staff's concern described in RAI 3.1.2.3.1.2-1 is resolved.

Aging Management - Although not specifically stated in the AMR line item, the applicant identified, treated, discussed, and assessed loss of preload due to stress relaxation in the Unit 2 spring-loaded core plate plugs as a TLAA in LRA Section 4.2.8. The applicant dispositioned the TLAA on the Unit 2 spring-loaded core plate plugs in accordance with 10 CFR 54.21(c)(1)(iii) in that the applicant proposed to credit the Reactor Vessel and Internals Structural Integrity Program (RV&ISIP) with the management of loss of preload due to stress relaxation in the Unit 2 spring-loaded core plate plugs. The applicant's AMR is therefore consistent with the manner the applicant dispositioned the TLAA for the Unit 2 spring-loaded core plate plugs and is acceptable. Based on this analysis, the staff concluded that the RV&ISIP is an appropriate AMP to credit for aging management of the Unit 2 spring-loaded core plate plugs.

The staff evaluated the TLAA on stress relaxation of the Unit 2 spring-loaded core plate plugs in SER Section 4.2.8. The staff evaluated the RV&ISIP in SER Section 3.0.3.3.1. The staff's evaluation of the RV&ISIP includes an assessment of the applicant's response to RAI B.2.28-5, which was issued to request specific details on how the RV&ISIP would be used to manage loss of preload due to stress relaxation of the Unit 2 spring-loaded core plate plugs.

Loss of Material and Cracking in Stainless Steel and Nickel-based Alloy RV Internal Components that are Exposed to the Treated Water (Including Steam) Environment

Identification of Aging Effects - The applicant identified all of the RV internal components (including RV penetrations and interior RV attachment welds) exposed to the treated water (and its steam) environment. For these components, the treated water (and its steam) environment is that of the reactor coolant environment.

The applicant identified cracking due to SCC as an AERM for all stainless steel and nickel-based alloy RV internal components (including RV attachment welds) that are exposed to the reactor coolant (or its steam) environment and have corresponding AMR commodity group line items in GALL Report, Volume 2. The applicant also identified that cracking due to cyclical loading is an AERM for a number of stainless steel or nickel-based alloy RV internal components that are exposed to the reactor coolant (or its steam) environment and have corresponding AMR commodity group line items in GALL Report, Volume 2. The staff evaluated these "consistent-with-GALL" AMR line items in either SER Section 3.1.2.1 or 3.1.2.2.

The applicant also included a number of plant-specific AMR line items for the RV internal components. For these plant-specific AMRs, the applicant identified cracking due to SCC (including IASCC for those RV internal components in high neutron fluence areas) as an AERM for the following stainless steel and nickel-based alloy RV internal components that are exposed to the reactor coolant (or its steam) environment (including carbon steel or low-alloy steel components clad with stainless steel):

- core shroud repair hardware (core shroud repair clamps)
- nickel alloy (Unit 1) and stainless steel (Unit 2) core plate plugs
- jet pump assembly components, including the jet pump sensing lines, jet pump holddown beams, jet pump keepers, jet pump lock plates, and jet pump bolts
- orificed fuel support plates
- NSR steam dryers
- NSR core shroud heads and separators
- NSR feedwater spargers
- NSR RV surveillance capsule holders

The applicant clarified that GALL Report, Volume 2, does not address SCC or IASCC as an AERM for these RV internal components. However, since these components are made from materials that are identical to those for the stainless steel or nickel-alloy RV internal components that have AMR commodity group line items on SCC/IASCC in GALL Report, Volume 2, and since the applicant conservatively identified that cracking due to SCC/IASCC is an applicable aging effect for these components, the staff concluded that the applicant's determination is consistent with similar AMR commodity group line items in GALL Report, Volume 2, for other RV internal components that are made from stainless steel or nickel-based alloy materials. Based on this analysis, the staff concluded that the applicant's determination is acceptable.

The staff has emphasized that GALL Report, Volume 2, does not identify cracking due to SCC or cyclical loading as an AERM for BWR steam dryers. However, the applicant did identify cracking due to SCC and cyclical loading as an applicable AERM for the NSR steam dryers. This determination is consistent with an applicant action item identified in ACRS Correspondence Letter ACRSR-2091, dated September 14, 2004, to the Commission. In this letter, the ACRS stated that cracking of BWR steam dryers as a result of either cyclical loading or SCC should be managed for BWR LRAs. Thus, the applicant's AMR for the steam dryers is consistent with the ACRS determination and is acceptable.

The applicant identified that loss of material due to pitting and crevice corrosion are applicable aging effects for stainless steel and nickel-based alloy RV internal components that are exposed to the reactor coolant (or its steam) environment. These components include any low-alloy steel RV penetrations that are clad internally with stainless steel and interior stainless RV attachment welds. Stainless steel components are normally designed to be resistant to pitting and crevice corrosion in the absence of significant concentrations of dissolved oxygen or anionic impurities. GALL Report, Volume 2, does not indicate that loss of material due to general, pitting, or crevice corrosion is an AERM for the RV internal components fabricated from stainless steel or nickel-based alloys. The applicant credits and implements its Water Chemistry Program for the purpose of controlling the chemistry of the reactor coolant to within acceptable levels in accordance with the BWRVIP/EPRI water chemistry guidelines. This is conservative to the AMR commodity group line items that are listed in GALL Report, Volume 2, for stainless steel and nickel-based alloy RV internal components and, therefore, is acceptable.

<u>Aging Management Programs</u> - The applicant credits the RV&ISIP with the management of cracking due to either cyclical loading or SCC (including IASCC for RV internal components in high neutron fluence areas) and loss of material due to pitting or crevice corrosion for stainless steel and nickel-based alloy RV internal components having plant-specific AMRs. This program is defined in LRA Section B.2.28 and is an acceptable plant-specific AMP that is described in terms how the RV&ISIP conforms to the 10 program attributes recommended for AMPs in Agreed Branch Position RLEP-001. The program discussion includes the ability of the RV&ISIP to manage aging in the RV internal components. The staff confirmed that loss of material due to pitting and crevice corrosion and cracking due to SCC/IASCC and cyclical loading are aging effects that are within the scope of the AMP. Based on this assessment, the staff concluded that the RV&ISIP is an acceptable AMP to credit for management of these aging effects in the stainless steel and nickel-based alloy RV internal components. The staff evaluated the ability of the RV&ISIP to manage loss of material and cracking of the stainless steel RV internal components in SER Section 3.0.3.3.1.

The applicant also credits the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in the stainless steel and nickel-based alloy RV internal components. The staff concluded that this is an acceptable AMP for aging management because it will be used to control the concentrations of dissolved oxygen and ionic water impurities that, if left uncontrolled, could potentially lead to corrosion-induced cracking or loss of material aging mechanisms in the components. The applicant controls the concentrations of dissolved oxygen and ionic water impurities to acceptable levels as recommended in the EPRI/BWRVIP water chemistry guidelines. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentration of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

The applicant did include a plant-specific AMR line item for the jet pump sensing lines that identified cracking due to SCC and loss of material due to pitting and crevice corrosion as applicable AERMs for the components. However, the corresponding AMR line item on cracking due to SCC and loss of materials due to pitting and crevice corrosion of the jet pump sensing lines did not credit any AMP with management of the aging effects. To correct this, the applicant provided a supplemental response to RAI B.2.28-1, by letter dated July 18, 2005, and amended its AMR on loss of material due to pitting and crevice corrosion of the jet pump sensing lines. In this response, the applicant credited the RV&ISIP and Water Chemistry Program with management of loss of material due to pitting and crevice corrosion of the jet pump sensing lines.

For the jet pump sensing lines, the RV&ISIP references the management strategy in agreed-approved Topical Report BWRVIP-41-A as the basis for managing aging in the jet pump assembly components, including the jet pump sensing lines. In BWRVIP-41-A, the BWRVIP stated that augmented inspection activities of the jet pump sensing lines were not necessary because potential failures of the components are adequately addressed by the limiting conditions for operation (LCOs) and surveillance requirements for the jet pumps in the BWR TS. The BWRVIP clarified that any failure of a jet pump sensing line would result in an inoperability determination for the jet pumps and that this would lead to a plant operating mode change from operations at critical conditions.

For BSEP, the applicable TS requirements for the jet pumps are LCO 3.4.2 and Surveillance Requirement 3.4.2.1. Surveillance Requirement 3.4.2.1 requires surveillance monitoring of the jet pumps once every 24 hours to verify either that the recirculation pump-flow-to-speed ratio differs only by 5 percent or less from established patterns, or that the jet pump diffuser-to-lower-plenum differential pressure varies by 10 percent or less from that of the jet pump's established pattern. The action statement in LCO 3.4.2 requires the respective BSEP unit to be in hot standby (Mode 3) within 12 hours of an inoperability determination of a jet pump, including that which would be made following a failure of a jet pump sensing line. Although fulfillment of the TS requirements does not by itself constitute an adequate basis for aging management under 10 CFR Part 54, when coupled with the crediting the Water Chemistry Program for aging management the staff concluded that the applicant established a conservative aging management strategy for the jet pump sensing lines, as based on the following:

(1) The applicant conservatively included the jet pump sensing lines within the scope of license renewal and the scope of an AMR analysis.

(2) The Water Chemistry Program will be used to mitigate the probability that loss of material due to pitting or crevice corrosion or cracking due to SCC will occur in the jet pump sensing lines, and to minimize the concentrations of dissolved oxygen and ionic impurities in the reactor coolant that could, if left uncontrolled, lead to these aging effects. As demonstrated by its supplemental response to RAI B.2.28/ RAI 3.1.2.3.1.2-3, dated July 18, 2005, the applicant maintains the concentrations of impurities in the reactor coolant to extremely low concentrations, on the order of a few tenths of a percent parts per billion, and, therefore, is maintaining the reactor coolant at a high purity level.

(3) Should the Water Chemistry Program fail to achieve its purpose for mitigating corrosive aging mechanisms, and should a BSEP jet pump sensing lines fail as a result of loss of material due to pitting, crevice corrosion, or cracking due to SCC, the implementation of the applicable BSEP TS will place the effected unit on "hot standby" within 12 hours of the jet pump inoperability determination, including a jet pump sensing line failure. The daily

> surveillance requirements for monitoring jet pump differential pressure and/or recirculation pump flow-to-speed ratio will indicate that the jet pump sensing lines are achieving their intended functions.

Based on this determination, the staff concluded that it is acceptable to credit the Water Chemistry Program and the required TS 3.4.2 action statement, as invoked through the RV&SIP and BWRVIP-41-A, as the basis for aging management of loss of material due to pitting or crevice corrosion or cracking due to SCC in the jet pump sensing lines because the applicant has credited an acceptable AMP for aging management and because the TS process will be used as a basis for confirming that the Water Chemistry Program is achieving its function of mitigating corrosion effects in the components.

Cracking due to Cyclical Loading in the Low Alloy Steel RV Drain Lines

<u>Identification of Aging Effects</u>. - The applicant identified cracking due to cyclical loading as an AERM for the RV drain line penetrations exposed to the treated water (including steam) environment. For this component, the treated water environment is reactor coolant, or its steam. The applicant's AMR did not identify that the RV drain line penetrations were clad with stainless steel and therefore identified that this AMR was plant-specific because the material for these components is not addressed in any corresponding AMR commodity group line item in GALL Report, Volume 2. In contrast, AMR commodity group line item IV.A1.5-a of GALL Report, Volume 2, does identify that cracking due to SCC, IGSCC, or cyclical loading is an AERM for stainless steel (SB-167) RV drain lines. Cracking due to cyclical loading is a mechanical type of aging mechanism that results from the loading and unloading of an applied stress on a component. The isolation valves in the RV drain lines are only opened periodically at the times the applicant wants to use the drain lines to send and purify the reactor coolant through the reactor water cleanup system. Thus, the RV drain lines are subject to only infrequent cycling. In spite of this, the applicant identified cracking due to cyclical loading as an AERM for these components. Since this is conservative, the staff concluded that the applicant's identification of cracking due to cyclical loading as an AERM for the low-alloy steel RV drain line penetrations is acceptable.

In RAI 3.1.2.3.1.2-2, dated May 18, 2005, the staff stated that industry experience has not yet demonstrated that SCC and IGSCC are AERMs for RV penetrations that are fabricated from unclad low-alloy steel. However, industry experience demonstrated the cracking of nickel-based alloy weld filler metals may be an AERM for the industry. Thus, cracking due to SCC or IGSCC could occur in the low-alloy steel RV drain line penetrations if the structural welds that are used to join the drain lines to the RVs are fabricated from nickel-based alloy weld filler metals. Therefore, the staff requested that the applicant clarify whether the structural welds for the RV drain line penetrations are fabricated from nickel-based alloy weld filler metals, and if so, to explain the basis for omitting cracking due to SCC or IGSCC as an applicable AERM for these components.

In its response, dated June 14, 2005, the applicant stated:

> Nickel-based alloys were not used in the fabrication of the drain nozzle. The low-alloy steel nozzle was joined to the low-alloy steel reactor vessel using low-alloy steel weld material. Therefore, cracking due to SCC, including IGSCC, is not an applicable aging effect.

The applicant's response to RAI 3.1.2.3.1.2-2 confirms that the low-alloy steel RV drain line penetrations were adjoined to the lower RV heads (which were also made from low-alloy steel) using a low-alloy steel weld metal. Since the applicant confirmed that the structural welds for the drain line penetrations were made from low-alloy steel weld material and not nickel alloy weld material, the staff agreed that SCC does not need to be identified as an AERM in the LRA for the RV drain line penetrations and that cyclical loading is the only mechanism for cracking that needs to be managed for the RV drain line penetrations during the extended period of operation. Therefore, the staff's concern described in RAI 3.1.2.3.1.2-2 is resolved.

<u>Aging Management Programs</u> - The applicant credits the RV&ISIP with the management of cracking due to cyclical loading in the low-alloy steel RV drain line penetrations. The scope of the applicant's RV&ISIP includes recommended inspection and flaw evaluation guidelines of Agreed-approved Topical Report BWRVIP-74-A. The staff-approved guidelines of BWRVIP-74-A include recommended inspections for RV penetration nozzles. The staff therefore concludes that it is acceptable to credit the RV&ISIP as the basis for managing cracking due to cyclical loading of the RV drain line penetrations. The staff assesses the ability of the RV&ISIP to manage cracking due to cyclical loading of the RV drain line penetrations in SER Section 3.0.3.3.1.

Flow Blockage of Stainless Steel RV Internal Spray Nozzles as a Result of Fouling

<u>Identification of Aging Effects</u>. In RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part A, dated May 18, 2005, the staff stated that the applicant identified flow blockage due to fouling as an additional AERM for the stainless steel core spray nozzles. Therefore, the staff requested that the applicant identify what type of fouling mechanisms could impede emergency coolant flow through the core spray nozzles if the core spray system was required to initiate in response to a design-basis accident or operational transient. In its response, by letter dated June 14, 2005, the applicant stated:

> Corrosion products associated with loss of material are considered capable of impeding the flow of emergency coolant through the core spray nozzles. As shown in Table 3.1.2-1, flow blockage due to fouling is managed with a combination of the Water Chemistry Program and the Reactor Vessel and Internals Structural Integrity Program. The Water Chemistry Program mitigates the formation of corrosion products by controlling oxygen, chlorides, sulfates, etc. The verification that the Water Chemistry Program is effective is through the use of the Reactor Vessel and Internals Structural Integrity Program. The inspection of the core spray components is through BWRVIP-18-A. The NRC has previously found that the use of inspections per the BWRVIP guidelines is adequate.

The applicant's response to RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part A addressed the potential cause of flow blockage in the core spray sparger nozzles and identified precipitation of corrosion products resulting from potential impurities in the reactor coolant as the mechanism that could potentially induce flow blockage in the core spray sparger nozzles. RAI B.2.28/RAI 3.1.2.3.1.2-3, with respect to identifying the mechanism that could potentially induce flow blockage in the core spray sparger nozzles, is therefore resolved.

In RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part B, dated May 18, 2005, the staff stated that LRA Table 3.1.2-1 includes an AMR line entry for the internal feedwater spargers. Therefore, the staff requested that the applicant clarify whether the feedwater nozzles were designed with spray nozzles, and, if so, whether flow blockage due to fouling should be identified as an applicable aging effect for the feedwater sparger nozzles.

In its response, by letter dated June 14, 2005, the applicant stated:

> The feedwater spargers do not have spray nozzles but have flow holes. The non-safety related feedwater spargers have been included within the scope of license renewal because of the potential for affecting safety related subcomponents of the reactor vessel and internals. The intended function of the feedwater spargers is M-4; i.e., provide structural support/seismic integrity. The feedwater spargers are managed to ensure gross structural integrity to prevent the formation of loose parts.

The applicant's response to RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part B, clarified that the feedwater spargers are designed with flow holes in lieu of nozzles. Therefore, the staff concluded that flow blockage is not an AERM of concern for the feedwater spargers, and the staff's concern described in RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part B, is resolved.

Aging Management Programs - The applicant credits the Water Chemistry Program and the RV&ISIP with the management of flow blockage in the core spray nozzles as a result of fouling. The Water Chemistry Program is an appropriate AMP to credit with aging management because the program is designed to minimize the concentrations of ionic impurities in the reactor coolant and secondary coolants which, if left uncontrolled, could potentially lead to corrosion products in the coolant. The staff evaluated the Water Chemistry Program in SER Section 3.0.3.1.

The RV&ISIP is an inspection-based AMP for the RV internal components but is not an appropriate inspection-based program to credit for flow blockage in the core spray sparger nozzles. The staff issued RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part A, in order to request additional information on how the RV&ISIP would be capable of managing flow blockage in these components during the extended period of operation. The staff evaluated the RV&ISIP in SER Section 3.0.3.3.1. The staff's evaluation of the RV&ISIP included an evaluation of the applicant's response to RAI B.2.28-7/RAI 3.1.2.3.1.2-3, Part A, as relevant to the ability of the AMP to inspect and monitor for potential flow blockage of the core spray sparger nozzles. The resolution of this RAI is addressed in SER Section 3.0.3.3.1.

Based on this assessment, the staff concluded that the applicant has credited an appropriate AMP (the Water Chemistry Program) to manage potential flow blockage of the core spray sparger nozzles.

Conclusion. The staff reviewed the applicant's plant-specific AMRs and RAI responses for evaluating the RV internal components (including the RV drain line penetrations and RV interior attachment welds) that are exposed to the treated water (including steam) environment. For these AMRs, the staff determined that the applicant identified the aging effects that are applicable to the RV internal components exposed to these environments. The staff also determined that the applicant has credited either an appropriate inspection-based AMP, an appropriate mitigative-based AMP, a TLAA, or a combination of these management strategies to manage the aging effects that are applicable to the RV internal components. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects of aging associated RV internal components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reactor Vessel (RV) and Internals - Piping, Fitting and Valve Components. The components subjected to this review include nozzle safe ends in the low pressure core spray (LPCS) system, recirculating water (inlet and outlet), feedwater, and instrumentation. The components also include piping, fitting and valve bodies in main steam, feedwater, and RV head vent.

The applicant's plant-specific AMRs for the RV piping, fitting and valve components are given in LRA Table 3.1.2-1. The specific components that are within the scope of LRA Table 3.1.2-1 include:

- Nozzle safe ends in LPCS, recirculating water (inlet and outlet), feedwater and instrumentation.
- Piping, fittings and valve bodies in main steam, feedwater, and RV head vent.

The applicant identified that the materials of fabrication for the components include carbon steel, stainless steel, and nickel-based alloys. The applicant identified that the applicable environments for these components include the indoor air environment (external) and the treated water (including steam) environment (internal).

Management of Specific Aging Effects Using Time Limited Aging Analyses (TLAAs) - Crack Initiation due to Thermal Fatigue

Identification of Aging Effects - The applicant identified cracking due to thermal fatigue as an applicable aging effect for all RV piping, fitting and valve components and their supports. This is consistent with SRP-LR; therefore, the staff concluded that the applicant's identification of RV piping, fitting and valve components that are subject to thermal fatigue is acceptable.

Aging Management - The applicant proposed to manage cracking due to thermal fatigue using TLAA for assessing thermal fatigue/cumulative fatigue damage of ASME Code Class 1 components, which is given in LRA Section 4.3. This is consistent with the SRP-LR and is, therefore acceptable. The staff evaluated the applicant's TLAA on thermal fatigue of ASME Code Class 1 components in SER Section 4.3.

RV Piping, Fitting and Valve Components that Are Exposed to the Indoor Air/Containment Air Environments

Identification of Aging Effects - For the RV piping, fitting and valve components, including components that are fabricated from either carbon steel, stainless steel, or nickel-based alloy materials, and including valves made of aluminum alloys or copper alloys, the applicant did not identify any AERMs that are exposed externally to the indoor air environment. The applicant's external indoor air environment for the RCS is divided into two types of atmospheric environments: (1) indoor air during refueling outages or (2) containment air during plant operations. The applicant provided the following definition of the indoor air environment:

> Atmospheric air, specific temperature range/humidity dependent upon building/room/area. Typically, temperature is 104 EF maximum in most areas and radiation dose levels are negligible. Potentially wetted.

The applicant also provides the following definition of the containment air environment:

Nitrogen atmosphere (atmospheric air during refueling outages). Specific temperature range dependent upon area. Bulk average temperature 150EF maximum. Relative humidity 40 - 90%. Pressure +2.5/-0.5 psig. Gamma radiation dose level: maximum 60-year total integrated dose (TID) 1.25 x 10^8 rad gamma (1.32 x 10^{10} rad gamma (54 EFPY) at inside face of sacrificial shield wall). Maximum neutron fluence (54 EFPY) of 4.03 x 10^{17} n/cm^2 (E>1 Mev) inside face of the sacrificial shield wall.

The predominant external environment for the RV piping, fitting and valve components is containment air because the indoor air environment only occurs during scheduled refueling outages for the plants, normally 6 to 12 percent of the time, depending on the length of the refueling outages.

The applicant included plant-specific Footnote 101 in LRA Table 3.1.2-1 through 3.1.2-4 as its basis for establishing its position that cracking or loss of material would not occur in stainless steel or nickel-based alloy components under the indoor/containment air environments. In this footnote, the applicant stated that stainless steel and nickel-based alloy components do not have any applicable aging effects in non-aggressive indoor air environments; that is, indoor air environments that do not contain significant aggressive chemical species. Since the indoor/containment air environments do not normally contain aggressive chemical species, the staff agreed that aging effects do not need to be identified for the stainless steel and nickel-based alloy components that are exposed to indoor/containment air environments and concluded that the applicant's assessment is acceptable.

The applicant included plant-specific Footnote 109 in LRA Table 3.1.2-1 through 3.1.2-4 as its basis for establishing its position that loss of material would not occur in carbon steel or low-alloy steel components under the indoor/containment air environments. In this footnote, the applicant stated that general corrosion is not a concern for the carbon steel/low-alloy steel components that are exposed to these environments because the components operate at temperatures equal to or above 212EF. The maximum bulk average temperature of the indoor/containment air environments is identified in the application as 150EF in LRA Table 3.0-2. Since the carbon steel/low-alloy steel components operate at temperatures above the maximum bulk average temperature for the indoor/containment air environments, the staff concluded that loss of material/general corrosion induced by the precipitation of water will not be an issue for the carbon steel/low-alloy steel components that are exposed to these environments. Furthermore, industry operating experience has not yet identified that SCC is an AERM for carbon steel/low-alloy steel components that are exposed to indoor air environments, in the absence of aggressive chemical species. Since the indoor/containment air environments do not normally contain aggressive chemical species, the staff agreed that SCC is not an AERM for the carbon steel/low-alloy steel components that are exposed to the indoor/containment air environments. Based on this assessment, the staff agreed that neither loss of material due to general corrosion nor cracking due to SCC need to be identified as AERMs for the carbon steel/low-alloy steel components that are exposed to indoor/containment air environments and concludes that the applicant's assessment is acceptable.

Aging Management Programs - The applicant did not identify any AERMs for the RV piping, fitting and valve components that are exposed to the indoor/containment air environments and therefore did not credit any AMPs with aging management. In the previous section, the staff provided its bases for concluding that there were no AERMs for the RV piping, fitting and valve components that are exposed to these environments. Therefore the staff concluded that, AMPs do not need to be credited for aging management of the RV piping, fitting and valve components that are exposed to indoor/containment air environments.

Stainless Steel and Nickel-based Alloy RV Piping, Fitting and Valve Components that Are Exposed to the Treated Water (Including Steam) Environment

The applicant identified that cracking induced by SCC and loss of material due to pitting and crevice corrosion are applicable aging effects for the stainless steel and nickel-based alloy components that are exposed internally to the treated water environment. For these components, which include low-alloy steel components that are clad internally with stainless steel, the treated water environment is reactor coolant or its steam. The applicant provided the following definition of the treated water (including steam) environment:

> Treated water is demineralized water and is the base water for all clean, closed loop systems. Depending on the system, treated water may require additional processing. Treated water can be deaerated, include corrosion inhibitors, biocides, or include a combination of these treatments. Steam generated from treated water is included in this environment category.
>
> Reactor Water: BSEP water quality parameters for use in the reactor coolant system.

The NRC has approved Topical Report BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal,” which provides the BWRVIP’s recommended inspection strategies and flaw evaluation recommendations for BWR RV components. The staff approved this report in an FSER to the BWRVIP, dated October 18, 2001. In this report, the BWRVIP indicated that cracking induced by SCC (and IGSCC and IASCC, which are forms of SCC) can be an AERM for stainless steel RV components that are exposed to a BWR reactor coolant environment. BWRVIP-74-A also indicates that SCC can be an AERM for nickel-based alloy RV components exposed to a BWR reactor coolant environment, particularly in nickel-based alloy weld filler metals fabricated from Alloy 182 or Alloy 82. The applicant’s identification of cracking due to SCC as an AERM for these components under internal exposure to reactor coolant is consistent with the age-related degradation analysis provided in BWRVIP-74-A and is, therefore, acceptable.

Stainless steels and nickel-based alloys are normally designed to be resistant to general corrosion. In addition, crevice corrosion and pitting corrosion are not expected to be aging mechanisms of concern in the absence of elevated concentrations of dissolved oxygen or dissolved corrosive anionic impurities (such as sulfates or halide impurities) in the reactor coolant. Crevice and pitting corrosion are localized mechanisms that can induce loss of material in components that are located in crevice areas, where the exposure of the components to a particular coolant may be prolonged due to stagnant conditions. Neither GALL Report, Volume 2, nor Topical Report BWRVIP-74-A identified loss of material due to general, pitting, or crevice corrosion as an applicable AERM for stainless steel and nickel-based alloy RV components (including low-alloy steel RV components designed with internal stainless steel cladding) that are exposed to the reactor coolant (or its steam) environment. In contrast, the applicant identified loss of material due to pitting and crevice corrosion as an applicable AERM for these components exposed to these environments. The staff concluded that this is acceptable because it is conservative relative to the aging-effect analysis approved in BWRVIP-74-A or the staff's recommended AMR commodity group line items identified in GALL Report, Volume 2, for stainless steel or nickel-based alloy RV piping, fitting and valve components in the reactor coolant pressure boundary.

Aging Management Programs - The applicant credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program with aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel and nickel-based alloy RV piping, fitting and valve components that are exposed to the reactor coolant (or its steam) environment. The applicable ISI examinations for these components are required by 10 CFR 50.55a and are defined in applicable inspection categories of Table IWB-2500-1 to Section XI of the ASME Code. Table 4-1 of Topical Report BWRVIP-74-A provides a summary of the ISI inspections that are required for RV piping, fitting and valve components. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the required ISI examinations as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in SER Section 3.0.3.1.

U.S. owners of BWRs implement comprehensive water chemistry control programs to minimize the concentrations of the dissolved oxygen and anionic impurities in the reactor coolant. The applicant's Water Chemistry Program has been implemented to satisfy the recommended concentrations for impurities in the EPRI/BWRVIP BWR water chemistry guidelines. Therefore, crediting of the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion is acceptable because implementation of the AMP will be in accordance with the EPRI/BWRVIP water chemistry guidelines and will be used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to these aging mechanisms. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentrations of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

Carbon Steel and Low Alloy Steel RV Piping, Fitting and Valve Components that Are Exposed to the Treated Water (Including Steam) Environment

Identification of Aging Effects - Not all of the low-alloy steel RV piping, fitting and valve components are cladded with austenitic stainless steel. Therefore, the applicant identified loss of material due to general, pitting, and crevice corrosion as an applicable aging effect for those carbon steel/low-alloy steel components whose surfaces are exposed internally to the treated water environment. The treated water environment has been described in the previous subsection and, for these components, is either reactor coolant or its steam.

Topical Report BWRVIP-74-A indicates that loss of material due to general corrosion is an AERM for carbon steel/low-alloy steel RV components exposed to a BWR reactor coolant environment, even though the BWRVIP states that the amount of general corrosion in the components is expected to be small. The report, as approved by the NRC, does not indicate that cracking due to

SCC (including IASCC or IGSCC) is an applicable aging effect for the carbon steel/low-alloy steel components that are exposed to the reactor coolant (or its steam) environment. The applicant identified loss of material due to general corrosion as an AERM for these components and included pitting corrosion and crevice corrosion within the scope of the mechanisms that could lead to this aging effect. This is acceptable to the staff because it adds pitting corrosion and crevice corrosion to general corrosion as mechanisms that can lead to loss of material in these components and is, therefore, consistent with, or more conservative than, the corresponding age-related degradation analysis provided in NRC-approved Topical Report BWRVIP-74-A.

Aging Management Programs - The applicant credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program with aging management of loss of material due to general, pitting, and crevice corrosion in the carbon steel/low-alloy steel RV piping, fitting and valve components that are exposed to the reactor coolant (or its steam) environment. The applicable ISI examinations for these components are required by 10 CFR 50.55a and are defined in applicable ISI categories of Table IWB-2500-1 to Section XI of the ASME Code. Table 4-1 of BWRVIP-74-A provides a summary of the inspections that are required for RV piping, fitting and valve components. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for the management of loss of material due to general, pitting, and crevice corrosion is acceptable because the applicant will apply the required ISI examinations as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage this aging effect and mechanisms in SER Section 3.0.3.1.

The applicant credited the Water Chemistry Program for aging management to minimize the concentrations of dissolved oxygen and ionic water impurities that, in elevated concentrations, could potentially lead to cracking due to SCC and loss of material due to general, pitting and crevice corrosion of low-alloy steel/carbon steel in reactor coolant pressure boundary components. The staff concluded that this is an acceptable AMP for aging management because it will be used to control the concentration of dissolved oxygen and ionic water impurities to acceptable levels, as recommended in the EPRI/BWRVIP water chemistry guidelines. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentration of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

Conclusion. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects associated with the RV piping components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.2 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Neutron Monitoring System (NMS) – Table 3.1.2-2

The staff reviewed LRA Table 3.1.2-2, which summarizes the results of AMR evaluations for the NMS component groups.

The applicant’s plant-specific AMRs for piping, fitting and valve components in the NMS are given in LRA Table 3.1.2-2. The specific components that are within the scope of LRA Table 3.1.2-2 include:

- piping, fittings and valve bodies included in the RCS but outside of the reactor coolant pressure boundary.
- incore neutron flux monitor guide tubes

The applicant identified that these components are made of stainless steels. For the guide tubes, the applicant identified that the applicable environments include the indoor air environment (external) and the treated water (including steam) environment (internal). For the rest of the components, the applicant identified that the applicable environments are the indoor air environment (external) and dry air/gas environment (internal).

Management of Specific Aging Effects Using Time Limited Aging Analyses (TLAAs) - Crack Initiation due to Thermal Fatigue

Identification of Aging Effects - The applicant identified cracking due to thermal fatigue as an applicable aging effect for all NMS piping, fitting and valve components and their supports. This is consistent with SRP-LR; therefore, the staff concluded that the applicant's identification of the NMS piping, fitting and valve components that are subject to thermal fatigue is acceptable.

Aging Management - The applicant proposed to manage cracking due to thermal fatigue using TLAA for assessing thermal fatigue/cumulative fatigue damage of ASME Code Class 1 components, which is given in LRA Section 4.3. This is consistent with the SRP-LR and is, therefore, acceptable. The staff evaluated the applicant's TLAA on thermal fatigue of ASME Code Class 1 components in SER Section 4.3.

Stainless Steel Components that Are Exposed to the Treated Water Environment

The applicant identified cracking induced by SCC and loss of material due to pitting and crevice corrosion as applicable aging effects for the stainless steel and nickel-based alloy piping, fitting and valve components in the NMS that are exposed internally to the treated water environment. For these components, the applicant provided the following definition of the treated water environment:

> Treated water is demineralized water and is the base water for all clean, closed loop systems. Depending on the system, treated water may require additional processing. Treated water can be deaerated, include corrosion inhibitors, biocides, or include a combination of these treatments. Steam generated from treated water is included in this environment category.
>
> Reactor Water: BSEP water quality parameters for use in the reactor coolant system.

Stainless steels and nickel-based alloys are normally designed to be resistant to general corrosion. In addition, crevice corrosion or pitting corrosion are not expected to be aging mechanisms of concern in the absence of elevated concentrations of dissolved oxygen or dissolved corrosive anionic impurities (such as sulfates or halide impurities) in the reactor coolant. Crevice and pitting corrosion are localized mechanisms that can induce loss of material in components located in crevice areas, where the exposure of the components to a particular coolant may be prolonged due to stagnant conditions. The GALL Report, Volume 2, did not identify loss of material due to general, pitting, or crevice corrosion as an applicable AERM for stainless steel components exposed to the treated water environment. In contrast, the applicant identified that loss of material due to pitting and crevice corrosion is an applicable AERM for these components exposed to the environment. The staff concluded that this is acceptable because it is conservative relative to the staff's recommended AMR commodity group line items identified in GALL Report, Volume 2, for stainless steel components.

Aging Management Programs - The applicant credited the Water Chemistry Program and the Reactor Vessel and Internal Structural Integrity Program with aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel components that are exposed to the reactor coolant (or its steam) environment. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the programs as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the Reactor Vessel and Internal Structural Integrity Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in SER Section 3.0.3.1.

U.S. owners of BWRs implement comprehensive water chemistry control programs to minimize the concentrations of the dissolved oxygen and anionic impurities in the reactor coolant. The applicant's Water Chemistry Program is implemented to satisfy the recommended concentrations for impurities in the EPRI/BWRVIP BWR water chemistry guidelines. Therefore, crediting of the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion is acceptable because implementation of the AMP will be in accordance with the ERPI/BWRVIP water chemistry guidelines and will be used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to these aging mechanisms. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentrations of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

Conclusion. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects associated with the NMS components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.3 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Manual Control System – Table 3.1.2-3

The staff reviewed LRA Table 3.1.2-3, which summarizes the results of AMR evaluations for the reactor manual control system component groups.

The applicant's plant-specific AMRs for piping and fittings in the reactor manual control system are given in LRA Table 3.1.2-3. The specific components that are within the scope of LRA Table 3.1.2-3 include piping and fittings in the RCS but outside of the RCPB.

The applicant identified that these components are made of stainless steels and that the applicable environments include the indoor air environment (external) and the treated water (including steam) environment (internal).

Management of Specific Aging Effects Using Time Limited Aging Analyses (TLAAs) - Stainless Steel Components that Are Exposed to the Treated Water Environment

The applicant identified cracking induced by SCC and loss of material due to pitting and crevice corrosion as applicable aging effects for stainless steel components exposed internally to treated water.

The NRC has approved Topical Report BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," which provides the BWRVIP's recommended inspection strategies and flaw evaluation recommendations for BWR RV components. The staff approved this report in an FSER to BWRVIP, dated October 18, 2001. In this report, the BWRVIP indicated that cracking induced by SCC (including IGSCC and IASCC, which are forms of SCC) can be an AERM for stainless steel RV components that are exposed to a BWR reactor coolant environment. BWRVIP-74-A also indicates that SCC can be an AERM for nickel-based alloy RV components that are exposed to a BWR reactor coolant environment, particularly in nickel-based alloy weld filler metals that are fabricated from Alloy 182 or Alloy 82. The applicant's identification that cracking due to SCC is an AERM for these components under internal exposure to the reactor coolant is consistent with the age-related degradation analysis provided in BWRVIP-74-A and is, therefore, acceptable.

Stainless steels and nickel-based alloys are normally designed to be resistant to general corrosion. In addition, crevice corrosion or pitting corrosion are not expected to be aging mechanisms of concern in the absence of elevated concentrations of dissolved oxygen or dissolved corrosive anionic impurities (such as sulfates or halide impurities) in the reactor coolant. Crevice and pitting corrosion are localized mechanisms that can induce loss of material in components that are located in crevice areas, where exposure of the components to a particular coolant may be prolonged due to stagnant conditions. GALL Report, Volume 2, did not identify loss of material due to general, pitting, or crevice corrosion as an applicable AERM for stainless steel components exposed to treated water. In contrast, the applicant identified loss of material due to pitting and crevice corrosion as an applicable AERM for these components exposed to this environment. The staff concluded that this is acceptable because it is more conservative relative to the staff's recommended AMR commodity group line items identified in GALL Report, Volume 2, for stainless steel components.

<u>Aging Management Programs</u> - The applicant credited the Water Chemistry Program and the One-Time Inspection Program with aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel components that are exposed to treated water. The staff concluded that crediting the One-Time Inspection Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the programs as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the One-Time Inspection Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in SER Section 3.0.3.1.

U.S. owners of BWRs implement comprehensive water chemistry control programs to minimize concentrations of dissolved oxygen and anionic impurities in the reactor coolant. The applicant's Water Chemistry Program is implemented to satisfy the recommended concentrations for impurities in the EPRI/BWRVIP BWR water chemistry guidelines. Therefore, crediting of the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion is acceptable because implementation of the AMP will be in accordance with the ERPI/BWRVIP water chemistry guidelines and will be used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to these aging mechanisms. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentrations of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

Conclusion. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects associated with the reactor manual control system components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.4 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Control Rod Drive (CRD) Hydraulic System – Table 3.1.2-4

The staff reviewed LRA Table 3.1.2-4, which summarizes the results of AMR evaluations for the CRD hydraulic system component groups.

The applicant's plant-specific AMRs for the RCS control rod drive hydraulic system components are given in LRA Table 3.1.2-4. The specific components within the scope of LRA Table 3.1.2-4 include:

- piping, fittings and valve bodies
- tanks
- rupture disks and filters
- control rod drive housing (CRDH) pump casing and gearbox coolers

The applicant identified that the materials of fabrication for the piping, fittings, valve bodies, tanks, rupture disks, filters, pump casing and gearbox coolers include carbon steel, stainless steel, copper alloys and nickel-based alloys. The applicant identified that the applicable environments for these components include the indoor air environment (external), dry air/gas environment (internal), lube oil (internal) environment, and the treated water environment (internal).

Management of Specific Aging Effects Using TLAAs - Carbon Steel Components Exposed to Indoor Air that are Operated at below 212EF

The applicant identified loss of material due to general corrosion as an applicable aging effect for the carbon steel components exposed to moist air and humidity. The staff found this identification consistent with GALL Report, Volume 2, Item VII.I.1-b. Therefore, the staff concluded that the applicant's identification of the control rod drive hydraulic system (CRDHS) carbon steel components that are subject to loss of material in an indoor environment is acceptable.

Stainless Steel Components that Are Exposed to the Treated Water Environment

<u>Identification of Aging Effects</u> - The applicant identified cracking induced by SCC and loss of material due to pitting and crevice corrosion as applicable aging effects for the stainless steel components exposed internally to the treated water environment.

The NRC has approved Topical Report BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," which provides the BWRVIP's recommended inspection strategies and flaw evaluation recommendations for BWR RV components. The staff approved this report in an FSER to the BWRVIP, dated October 18, 2001. In this report, the BWRVIP indicated that cracking induced by SCC (including IGSCC and IASCC, which are forms of SCC) can be an AERM for stainless steel RV components that are exposed to a BWR reactor coolant environment. BWRVIP-74-A also indicates that SCC can be an AERM for nickel-based alloy components that are exposed to a BWR reactor coolant environment.

The applicant's identification that cracking due to SCC is an AERM for the CRDHS piping fitting and valve components under internal exposure to the reactor coolant is consistent with the age-related degradation analysis provided in BWRVIP-74-A and is, therefore, acceptable.

Stainless steels and nickel-based alloys are normally designed to be resistant to general corrosion. In addition, crevice corrosion or pitting corrosion are not expected to be aging mechanisms of concern in the absence of elevated concentrations of dissolved oxygen or dissolved corrosive anionic impurities (such as sulfates or halide impurities) in the reactor coolant. Crevice and pitting corrosion are localized mechanisms that can induce loss of material in components that are located in crevice areas, where exposure of the components to a particular coolant may be prolonged due to stagnant conditions. GALL Report, Volume 2, did not identify loss of material due to general, pitting, or crevice corrosion as an applicable AERM for the stainless steel components that are exposed to the treated water environment. In contrast, the applicant identified loss of material due to pitting and crevice corrosion as an applicable AERM for these components exposed to these environments. The staff concluded that this is acceptable, because it is more conservative relative to the staff's recommended AMR commodity group line items identified in GALL Report, Volume 2, for stainless steel components.

Aging Management Programs - The applicant credited the Water Chemistry Program and the One-Time Inspection Program with aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel components that are exposed to the treated water environment. The staff concluded that crediting the One-Time Inspection Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the programs as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the One-Time Inspection Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in SER Section 3.0.3.1.

U.S. owners of BWRs implement comprehensive water chemistry control programs to minimize the concentrations of the dissolved oxygen and anionic impurities in the reactor coolant. The applicant's Water Chemistry Program is implemented to satisfy the recommended concentrations for impurities in the EPRI/BWRVIP BWR water chemistry guidelines. Therefore, crediting the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion is acceptable because implementation of the AMP will be in accordance with the ERPI/BWRVIP water chemistry guidelines and will be used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to these aging mechanisms. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize concentrations of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

Carbon Steel Components that Are Exposed to the Treated Water (Including Steam) Environment

Identification of Aging Effects - Not all of the low-alloy steel CRDHS components are clad with austenitic stainless steel. Therefore, the applicant identified loss of material due to general, pitting, and crevice corrosion as an applicable aging effect for those carbon steel/low-alloy steel components whose surfaces are exposed internally to the treated water environment.

Topical Report BWRVIP-74-A indicates that loss of material due general corrosion is an AERM for carbon steel/low-alloy steel RV components that are exposed to a BWR reactor coolant environment, even though the BWRVIP states that the amount of general corrosion in the components is expected to be small. The report, as approved by the NRC, does not indicate that cracking due to SCC (including IASCC or IGSCC) is an applicable aging effect for carbon steel/low-alloy steel components exposed to the reactor coolant (or its steam) environment. The applicant identified that loss of material due to general corrosion is an AERM for these components and included pitting corrosion and crevice corrosion within the scope of the mechanisms that could lead to this aging effect. This is acceptable to the staff because it adds pitting corrosion and crevice corrosion (in addition to general corrosion) as mechanisms that can lead to loss of material in these components and is, therefore, more conservative than the corresponding age-related degradation analysis provided in NRC-approved Topical Report BWRVIP-74-A.

Aging Management Programs. The applicant credited the One-Time Inspection Program and the Water Chemistry Program with aging management of loss of material due to general, pitting, and crevice corrosion in the carbon steel/low-alloy steel components in the CRDHS that are exposed to the treated water environment. The staff concluded that crediting the One-Time Inspection Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the programs as the basis for managing these aging effects during the period of extended operation. In SER Section 3.0.3.1, the staff evaluated the ability of the One-Time Inspection Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion.

The applicant credited the Water Chemistry Program for aging management to minimize concentrations of dissolved oxygen and ionic water impurities that if present in elevated concentrations, could potentially lead to cracking due to SCC and loss of material due to general, pitting and crevice corrosion of low-alloy steel/carbon steel RCPB components. The staff concluded that this is an acceptable AMP for aging management because it will be used to control the concentration of dissolved oxygen and ionic water impurities to acceptable levels, as recommended in the EPRI/BWRVIP water chemistry guidelines. In Section SER 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentration of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

Conclusion. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects associated with the CRDHS components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.5 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Coolant Recirculation System – Table 3.1.2-5

The staff reviewed LRA Table 3.1.2-5, which summarizes the results of AMR evaluations for the reactor coolant recirculation system component groups.

The applicant's plant-specific AMRs for the RCS reactor coolant recirculation system components are given in LRA Table 3.1.2-5. This section also evaluated other Class 1 piping components that the applicant listed in LRA Tables 3.3.2-1, 3.3.2-2, and 3.3.2-3. The specific components that are within the scope of license renewal include:

- piping, fittings and valves (body)
- pump casing, cover, flange and closure bolting

The applicant identified that the materials of fabrication for the piping, fittings, valves (body), pump casing, cover, flange and closure bolting include carbon steel, low-alloy steel, stainless steel, and copper alloys. The applicant identified that the applicable environments for these components include the indoor air environment (external), dry air/gas environment (internal), and treated water environment (internal).

Management of Specific Aging Effects Using Time Limited Aging Analyses (TLAAs) - Cracking due to Thermal Fatigue

Identification of Aging Effects - The applicant identified cracking due to thermal fatigue as an applicable aging effect for all reactor coolant recirculation system (RCRS) components and their supports. This is consistent with SRP-LR; therefore, the staff concluded that the applicant's identification of piping, fitting, valve, and pump components subject to thermal fatigue is acceptable.

Aging Management - The applicant proposed to manage cracking due to thermal fatigue using the TLAA for assessing thermal fatigue/cumulative fatigue damage of ASME Code Class 1 components, which is given in LRA Section 4.3. This is consistent with the SRP-LR and is, therefore, acceptable. The staff evaluated the applicant's TLAA on thermal fatigue of ASME Code Class 1 components in SER Section 4.3.

Low Alloy Steel Loss of Materials due to Wear, Loss of Pre-load due to Relaxation, Bolting Integrity Program

Identification of Aging Effects - The applicant identified loss of materials due to wear and loss of pre-load due to relaxation as applicable aging effects for the pump closure bolting. This is consistent with GALL Report Item IV.C1.2-d and Item IV.C1.2-e. Therefore, the staff concluded that the applicant's identification of pump closure bolting components that are subject to loss of materials due to wear, loss of preload due to relaxation is acceptable.

Aging Management. The applicant proposed to manage loss of materials due to wear and loss of pre-load due to relaxation using its Bolting Integrity Program. The staff evaluated the SER Section 3.0.3.1.

Carbon Steel Components Exposed to Indoor Air that Are Operated at below 212EF

The applicant identified loss of material due to general corrosion as an applicable aging effect for the carbon steel components exposed to moist air and humidity. The staff found that this identification is consistent with GALL Report, Volume 2. Therefore, the staff concluded that the applicant's identification of CRDHS carbon steel components that are subject to loss of material in an indoor environment is acceptable.

Stainless Steel and Nickel-based Alloy RV Components that Are Exposed to Treated Water (Including Steam) Environment

The applicant identified that cracking induced by SCC and loss of material due to pitting and crevice corrosion are applicable aging effects for the stainless steel and nickel-based alloy components that are exposed internally to the treated water environment. For these components, which include low-alloy steel RV components that are clad internally with stainless steel, the treated water environment is reactor coolant. The applicant provides the following definition of the treated water (including steam) environment:

> Treated water is demineralized water and is the base water for all clean, closed loop systems. Depending on the system, treated water may require additional processing. Treated water can be deaerated, include corrosion inhibitors, biocides, or include a combination of these treatments. Steam generated from treated water is included in this environment category.
>
> Reactor Water: BSEP water quality parameters for use in the reactor coolant system.

The NRC has approved Topical Report BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," which provides the BWRVIP's recommended inspection strategies and flaw evaluation recommendations for BWR RV components. The staff approved this report in an FSER to the BWRVIP, dated October 18, 2001. In this report, the BWRVIP identified cracking induced by SCC (including IGSCC and IASCC, which are forms of SCC) as an AERM for stainless steel RV components exposed to a BWR reactor coolant environment. BWRVIP-74-A also indicates that SCC can be an AERM for nickel-based alloy components exposed to a BWR reactor coolant environment, particularly in nickel-based alloy weld filler metals that are fabricated from Alloy 182 or Alloy 82. The applicant's identification of cracking due to SCC as an AERM for these components under internal exposure to reactor coolant is analogous with the age-related degradation analysis provided in BWRVIP-74-A and is, therefore, acceptable.

Stainless steels and nickel-based alloys are normally designed to be resistant to general corrosion. In addition, crevice corrosion or pitting corrosion are not expected to be aging mechanisms of concern in the absence of elevated concentrations of dissolved oxygen or dissolved corrosive anionic impurities (such as sulfates or halide impurities) in the reactor coolant. Crevice and pitting corrosion are localized mechanisms that can induce loss of material in components that are located in crevice areas, where exposure of the components to a particular coolant may be prolonged due to stagnant conditions. Neither GALL Report, Volume 2, nor BWRVIP-74-A, identify loss of material due to general, pitting, or crevice corrosion as an applicable AERM for stainless steel and nickel-based alloy components (including those low-alloy steel RV components designed with internal stainless steel cladding) exposed to the reactor coolant environment. In contrast, the applicant identified loss of material due to pitting and crevice corrosion as an applicable AERM for these components exposed to this environment. The staff concluded that this is acceptable because it is conservative relative to the aging-effect analysis approved in BWRVIP-74-A or the staff's recommended AMR commodity group line items identified in GALL Report, Volume 2, for stainless steel or nickel-based alloy components in the RCPB.

Aging Management Programs. The applicant credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program with aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel and nickel-based alloy components that are exposed to the reactor coolant environment. The applicable ISI examinations for these components are required by 10 CFR 50.55a and are defined in applicable inspection categories of Table IWB-2500-1 to Section XI of the ASME Code. Table 4-1 of BWRVIP-74-A provides a summary of the ISI inspections that are required for these components. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for aging management of cracking due to SCC and loss of material due to pitting corrosion is acceptable because the applicant will apply the required ISI examinations as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in SER Section 3.0.3.1.

U.S. owners of BWRs implement comprehensive water chemistry control programs to minimize the concentrations of the dissolved oxygen and anionic impurities in the reactor coolant. The applicant's Water Chemistry Program is implemented to satisfy the recommended concentrations for impurities in the EPRI/BWRVIP BWR water chemistry guidelines. Therefore, crediting of the Water Chemistry Program for aging management of cracking due to SCC and loss of material due to pitting and crevice corrosion is acceptable because implementation of the AMP will be in accordance with the ERPI/BWRVIP water chemistry guidelines and will be used to minimize the concentrations of dissolved oxygen and ionic water impurities, that if present in elevated concentrations, could potentially lead to these aging mechanisms. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize concentrations of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

During its review, the staff determined that it needed additional information. The specific RAI and the applicant's response are discussed below.

In RAI 3.2-4, dated April 8, 2005, The staff stated that in LRA Tables 3.1.2-5 and 3.3.2-1, carbon and stainless steel small-bore piping and fittings less than NPS 4 in treated water (includes steam)(internal) environments, are subject to cracking due to thermal and mechanical loading. The Section XI Inservice Inspection and Water Chemistry Programs are credited to manage the identified aging effect. In the subject tables, stainless steel small-bore piping less than NPS 4, in the same treated water (includes steam) (internal) environment, are also subject to cracking due to SCC. The same AMPs are credited to manage the aging effect. Therefore, the staff requested that the applicant (1) provide the basis for the statement made under Note 226 that "cracking due to thermal and mechanical loadings was evaluated and dispositioned as not applicable," and (2) clarify the statement made under Note 226 that "The risk associated with cracking due to SCC is bounded by those components selected for inservice inspection as part of the Risk-Informed ISI Program..." Therefore, the staff requested the applicant to provide the technical basis for not including these components in the One-Time Inspection Program, as the staff questioned the effectiveness of the ASME Section XI inspection Program on this small bore piping.

In its response to RAI 3.2-4, by letter dated May 4, 2005, the applicant stated that these components are included in its revised One-Time Inspection Program, which satisfactorily answers the staff's concerns expressed in RAI 3.1.2.3.3-3.

The applicant further stated that susceptibility to cracking due to thermal and mechanical loading has been previously evaluated on a component-specific basis, in support of the BSEP RI-ISI submittal in Process Energy Carolinas (PEC) letter to the NRC dated April 20, 2001 (BSEP 01-0013). However, the applicant also stated that BSEP revised its comments during an audit of AMPs, and no longer credits RI-ISI in aging management. The applicant credits the Water Chemistry Program and ASME Section XI Subsection IWB, IWC and IWD Program for aging management of cracking, including SCC, in less than NPS 4 Class 1 piping components. The applicant stated that, consistent with the GALL Report, the One-Time Inspection Program will be used to verify the effectiveness of these programs. SER Section 3.0.3.11 provides the staff's discussion of the applicant's One-Time Inspection Program. It is noted that in its response to Audit Question B.2.15-1a, the applicant stated that in AMR Tables 3.1.2-5 and 3.3.2-1, the AMR line items addressing small-bore Class 1 piping will be revised to reflect Water Chemistry, ASME Section XI Subsection IWB, IWC and IWD, and One-Time Inspection Programs for aging management of cracking due to thermal and mechanical loading and SCC. In addition, the applicant noted that Note 226 is no longer applicable.

Based on the above information provided by the applicant, the staff considered that the applicant adequately clarified the aging management for small-bore Class 1 piping components, which are susceptible to cracking due to thermal and mechanical loading and SCC. Therefore, the staff's concerns described RAI 3.2-4 and RAI 3.1.2.3.3-3 are resolved.

Carbon Steel and Low Alloy Steel RCS Components that Are Exposed to the Treated Water (Including Steam) Environment

Identification of Aging Effects - Not all of the low-alloy steel components in the RCRS and other Class 1 components identified in LRA Tables 3.3.2-1, 3.3.2-2, and 3.3.2-3, are clad with austenitic stainless steel. Therefore, the applicant identified loss of material due to general, pitting, and crevice corrosion as an applicable aging effect for those carbon steel/low-alloy steel components whose surfaces are exposed internally to the treated water environment. The treated water environment has been described in the previous subsection and, for these components, is either the reactor coolant or its steam.

Topical Report BWRVIP-74-A indicates that loss of material due general corrosion is an AERM for carbon steel/low-alloy steel components that are exposed to a BWR reactor coolant environment, even though the BWRVIP states that the amount of general corrosion in the components is expected to be small. The report, as approved by the NRC, does not indicate that cracking due to SCC (including IASCC or IGSCC) is an applicable aging effect for the carbon steel/low-alloy steel components that are exposed to the reactor coolant (or its steam) environment. The applicant identified loss of material due to general corrosion as an AERM for these components and included pitting corrosion and crevice corrosion within the scope of the mechanisms that could lead to this aging effect. This is acceptable to the staff because it adds pitting corrosion and crevice corrosion to general corrosion as mechanisms that can lead to loss of material in these components and is, therefore, more conservative than the corresponding age-related degradation analysis provided in NRC-approved Topical Report BWRVIP-74-A.

Aging Management Programs - The applicant credited the Water Chemistry Program for aging management to minimize the concentrations of dissolved oxygen and ionic water impurities that, if present in elevated concentrations, could potentially lead to cracking due to SCC and loss of material due to general, pitting and crevice corrosion of low-alloy steel/carbon steel RCPB components. The staff concluded that this is an acceptable AMP for aging management because it will be used to control the concentration of dissolved oxygen and ionic water impurities to acceptable levels, as recommended in the EPRI/BWRVIP water chemistry guidelines. In SER Section 3.0.3.1, the staff evaluated the ability of the Water Chemistry Program to minimize the concentration of dissolved oxygen and ionic water impurities in the reactor coolant (or its steam) environment.

The applicant credited the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program and the Water Chemistry Program with aging management of loss of material due to general, pitting, and crevice corrosion in Class 1 carbon steel/low-alloy steel components exposed to reactor coolant. The applicable ISI examinations for these components are required by 10 CFR 50.55a and are defined in applicable ISI categories of Table IWB-2500-1 to Section XI of the ASME Code. Table 4-1of BWRVIP-74-A provides a summary of the inspections that are required for RV components. The staff concluded that crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program for the management of loss of material due to general, pitting, and crevice corrosion is acceptable, because the applicant will apply the required ISI examinations as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program to manage this aging effect and mechanisms in SER Section 3.0.3.1.

The applicant will include non-Class 1 carbon steel components exposed to a reactor coolant or its steam environment, in the One-Time Inspection Program, in addition to the Water Chemistry Program, for aging management of loss of material due to general, pitting, and crevice corrosion, as the basis for managing these aging effects during the period of extended operation. The staff evaluated the ability of the One-Time Inspection Program to manage this aging effect and mechanisms in SER Section 3.0.3.1.

Conclusion. On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated that the aging effects associated with the RCRS components will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging of the reactor vessel, internals, and RCS components, that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging the reactor vessel, internals, and RCS, as required by 10 CFR 54.21(d).

3.2 <u>Aging Management of Engineered Safety Features</u>

This section of the SER documents the staff's review of the applicant's AMR results for the ESF systems components and component groups associated with the following systems:

- residual heat removal system
- containment isolation system
- containment atmosphere control system
- high pressure coolant injection system
- automatic depressurization system
- core spray system
- standby gas treatment system
- standby liquid control system
- HVAC control building system
- reactor protection system

3.2.1 Summary of Technical Information in the Application

In LRA Section 3.2, the applicant provided AMR results for components. In LRA Table 3.2.1, "Summary of Aging Management Evaluations in Chapter V of NUREG-1801 for Engineered Safety Features," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the ESF systems components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the ESF systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detailed results of the staff's onsite audits are documented in the Audit and Review Report, dated June 21, 2005, and are summarized in SER Section 3.2.2.1.

During the audit, the staff reviewed the AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.2.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.2.2.2.

During the audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating (1) whether all plausible aging effects were identified, and (2) whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.2.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.2.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the ESF systems components, as required by 10 CFR 54.21(d).

Table 3.2-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.2, that are addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Engineered Safety Features System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, fittings, and valves in emergency core cooling system (Item Number 3.2.1-01)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Piping, fittings, pumps, and valves in emergency core cooling system (Item Number 3.2.1-02)	Loss of material due to general corrosion	Water chemistry and one-time inspection	Water Chemistry Program (B.2.2), One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems (Item Number 3.2.1-03)	Loss of material due to general corrosion	Plant specific	Systems Monitoring Program (B.2.29), Preventive Maintenance Program (B.2.30)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2)
Piping, fittings, pumps, and valves in emergency core cooling system (Item Number 3.2.1-04)	Loss of material due to pitting and crevice corrosion	Water chemistry and one-time inspection	Water Chemistry Program (B.2.2), One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2)
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems (Item Number 3.2.1-05)	Loss of material due to pitting and crevice corrosion	Plant specific	Systems Monitoring Program (B.2.29), Preventive Maintenance Program (B.2.30)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2)
Containment isolation valves and associated piping (Item Number 3.2.1-06)	Loss of material due to microbiologically influenced corrosion	Plant specific	Water Chemistry Program (B.2.2), One-Time Inspection Program (B.2.15), Systems Monitoring Program (B.2.29)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2)
Seals in standby gas treatment system (Item Number 3.2.1-07)	Changes in properties due to elastomer degradation	Plant specific	Systems Monitoring Program (B.2.29), Preventive Maintenance Program (B.2.30)	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2)
High pressure safety injection (charging) pump miniflow orifice (Item Number 3.2.1-08)	Loss of material due to erosion	Plant specific		Not applicable, PWR only
Drywell and suppression chamber spray system nozzles and flow orifices (Item Number 3.2.1-09)	Plugging of nozzles and flow orifices due to general corrosion	Plant specific	Protective Coatings Monitoring and Maintenance Program	Not consistent with GALL (See Section 3.2.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping and fittings of CASS in emergency core cooling system (Item Number 3.2.1-10)	Loss of fracture toughness due to thermal aging embrittlement	Thermal aging embrittlement of CASS		Not applicable
Components serviced by open-cycle cooling system (Item Number 3.2.1-11)	Local loss of material due to corrosion and/or buildup of deposit due to biofouling	Open-cycle cooling water system	Open-Cycle Cooling Water System Program (B.2.7)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.2)
Components serviced by closed-cycle cooling system (Item Number 3.2.1-12)	Loss of material due to general, pitting, and crevice corrosion	Closed-cycle cooling water system		Not applicable
Emergency core cooling system valves and lines to and from HPCI and RCIC pump turbines (Item Number 3.2.1-13)	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	Flow-Accelerated Corrosion Program (B.2.5)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Pumps, valves, piping, and fittings in containment spray and emergency core cooling systems (Item Number 3.2.1-14)	Crack initiation and growth due to SCC	Water chemistry		Not applicable, PWR only
Pumps, valves, piping, and fittings in emergency core cooling systems (Item Number 3.2.1-15)	Crack initiation and growth due to SCC and IGSCC	Water chemistry and BWR stress corrosion cracking	Water Chemistry Program (B.2.2), BWR Stress Corrosion Cracking Program (B.2.4)	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.2)
Carbon steel components (Item Number 3.2.1-16)	Loss of material due to boric acid corrosion	Boric acid corrosion		Not applicable, PWR only
Closure bolting in high pressure or high temperature systems (Item Number 3.2.1-17)	Loss of material due to general corrosion, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading or SCC	Bolting integrity		Not applicable (See Section 3.2.2.2)

The staff's review of the BSEP component groups followed one of three approaches depending on the group's consistency with the GALL Report. SER Section 3.2.2.1 discusses the staff's review and documentation of the AMR results for components in the ESF systems that the applicant indicated are consistent with the GALL Report and do not require further evaluation; SER Section 3.2.2.2 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended; and SER Section 3.2.2.3 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the ESF systems components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.2.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the ESF systems components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- BWR Stress Corrosion Cracking Program
- One-Time Inspection Program
- Open-Cycle Cooling Water System Program
- Preventive Maintenance Program
- Protective Coating Monitoring and Maintenance Program
- Selective Leaching of Materials Program
- Systems Monitoring Program
- Water Chemistry Program
- Flow-Accelerated Corrosion Program
- Buried Piping and Tanks Inspection Program

Staff Evaluation. In LRA Tables 3.2.2-1 through 3.2.2-9, the applicant provided a summary of AMRs for the ESF systems components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit of the information provided in the LRA, as documented in the BSEP Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

In the LRA Section 3.2, the applicant provided the results of its AMRs for the engineered safety features systems.

In the LRA Tables 3.2.2-1 through 3.2.2-9, the applicant provided a summary of the AMRs for components/commodities in the (1) RHR system; (2) containment atmospheric control (CAC) system; (3) HPCI system; (4) automatic depressurization system (ADS); (5) core spray (CS) system; (6) standby gast treatment system (SGTS); (7) SLC system; (8) HVAC control building system; and (9) reactor protection system.

Also, for each component type in LRA Table 3.2.1, the applicant identified those components that are consistent with the GALL Report where no further evaluation is required, those that are consistent with the GALL Report for which further evaluation is recommended, and those that are not addressed in the GALL Report together with the basis for their exclusion.

For AMRs that the applicant stated are consistent with the GALL Report and for which no further evaluation is recommended, the staff conducted its audit to determine whether the applicant's references to the GALL Report in the LRA are acceptable.

The staff reviewed its assigned LRA line-items to determine that the applicant (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the RHR, CAC, HPCI, ADS, CS, SGTS, SLC, HVAC control building, and reactor protection systems components that are subject to an AMR.

SER Sections 3.2.2.1.1 through 3.2.2.1.4, below, document the resolution of discrepancies identified by the staff during its audit of those AMRs that the applicant claimed are consistent with the GALL Report, and for which no further evaluation is recommended in the GALL Report.

3.2.2.1.1 Loss of Material and Crack Initiation and Growth in Closure Bolting in High Pressure and High Temperature Systems

In the discussion of LRA Table 3.2.1, item number 3.2.1-18, the applicant addressed aging management of closure bolting in the ESF systems. The applicant stated that the Bolting Integrity Program is not applicable since this system does not use high-strength pressure-boundary bolting. For non-Class 1 closure bolting, the applicant considers bolting to be a subcomponent of the associated component; therefore, bolting materials are not itemized as a separate component and the Bolting Integrity Program is not needed for aging management.

The staff reviewed LRA Tables 3.2.2-1 through 3.2.2-9 and noted that the applicant specified the Systems Monitoring Program for visual inspection of the external surfaces of components in the ESF systems, including any bolting associated with the component, to identify general corrosion. However, this AMP does not address the crack initiation and growth aging effect for pressure-retaining bolting. GALL AMP XI.M18 is recommended to manage loss of material due to general corrosion, and crack initiation and growth due to cyclic loading and/or SCC for all closure bolting in high-pressure or high-temperature systems that are within the scope of license renewal. The AMP recommended in the GALL Report does not exclude non-Class 1 bolting.

The staff reviewed the applicant's Bolting Integrity Program, and its evaluation is documented in SER Section 3.0.3.2.3. The applicant claims that this program is consistent with GALL AMP XI.M18. However, the Bolting Integrity Program has several major exceptions. For non-Class 1 pressure-retaining bolting, the Bolting Integrity Program excludes the ASME Section XI inservice inspection activities, along with monitoring and trending under the Systems Monitoring Program. Therefore, the staff determined that the Bolting Integrity Program, as presented in the LRA, would not be adequate to manage all of the aging effects identified for the non-Class 1 pressure-retaining bolting.

The staff requested the applicant to clarify how aging management of pressure-retaining bolting in the ESF systems would be managed during the extended period of operation.

As documented in the Audit and Review Report, the applicant provided the following response:

> The Bolting Integrity Program will be revised to include ASME, Section XI, activities identified in GALL, as well as aspects of monitoring and trending under Systems Monitoring for bolted connections outside of ASME, Section XI, boundaries. Subsequent to these revisions, the Bolting Integrity Program will be consistent with GALL with the exception that structural bolting is not addressed.
>
> Additionally, aging management review summaries in Sections 3.1, 3.2, 3.3, and 3.4 will be revised to address aging management requirements for each of the aging effects identified in GALL AMR line items pertaining to closure bolting in high pressure or high temperature systems. The following information will be included in these aging management reviews:
>
> 1) In general, BSEP treats bolting as a subcomponent of the parent component; and bolting does not have a separate line item in system level aging management reviews.
>
> 2) GALL identifies loss of material, loss of preload and cracking as applicable aging effects for high temperature, high pressure bolting.
>
> 3) The Bolting Integrity Program, updated as described above, is specified to manage these aging effects.

During the audit, the staff determined that, upon completion of the revisions noted in the applicant’s response, above, the Bolting Integrity Program will be consistent with the GALL Report for all pressure-retaining bolting. Structural bolting will not be addressed. Since BSEP treats bolting as a subcomponent of the pressure-retaining components, there are no separate AMRs in the LRA for bolting in the ESF system. However, the applicant’s commitment to specify the Bolting Integrity Program to manage all aging effects identified in the GALL Report for components containing Class 1 and non-Class 1 pressure-retaining bolting will resolve this discrepancy.

Since the revised Bolting Integrity Program will be consistent with the recommendation of GALL AMP XI.M18, the staff concluded that aging of pressure-retaining bolting in the ESF systems will be adequately managed. On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.2.2.1.2 Loss of Material for Valve Bodies in the Residual Heat Removal System

In the discussion section of LRA Table 3.2.2-1, the applicant stated that it includes AMR line items for valve bodies and bonnets in the residual heat removal system that are constructed of copper alloys and stainless steel, and exposed to raw water internally. The Open-Cycle Cooling Water System Program is specified to manage loss of material due to various corrosion mechanisms, and flow blockage due to fouling for these components. In addition, the Selective Leaching of Materials Program is specified to manage loss of material due to selective leaching for the copper-alloy components. GALL Report line item VII.C1.2-a is referenced, which also recommends the Open-Cycle Cooling Water System Program and the Selective Leaching of Materials Program. However, the AMRs identify generic Note E, indicating they are consistent with GALL with the exception of the AMP. The staff noted that other AMRs in Table 3.2.2-1 for piping and heat exchangers with similar materials and environments in this system identify generic Notes A or B, indicating that the AMPs are consistent with the GALL Report. During the audit, the staff asked the applicant to clarify this apparent inconsistency in the generic notes.

As documented in the Audit and Review Report, the applicant stated that the AMR line items for valves should be consistent with comparable line items for piping and heat exchanger components. Specifically, the line item for valves (body and bonnet) in LRA Table 3.2.2-1 associated with flow blockage due to fouling, loss of material due to crevice corrosion, loss of material due to MIC, and loss of material due to pitting corrosion should appropriately include generic Note A; selective leaching should include generic Note B.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.2.2.1.3 Loss of Material for Carbon Steel Piping and Fittings in the HVAC Control Building System

In the discussion section of LRA Table 3.2.2-8, the applicant stated that it includes an AMR line item for piping and fittings in the HVAC control building system that are constructed of carbon steel and exposed to indoor air on the internal surfaces. The Preventive Maintenance Program is specified to manage loss of material due to general corrosion for these components; however, GALL Report line item VII.D.1-a recommends the Compressed Air Monitoring Program to manage this aging effect. During the audit, the staff requested clarification on what preventive maintenance is performed on these components and how their interior surfaces are inspected for general corrosion by the Preventive Maintenance Program.

In its response, the applicant stated that this AMR line item represents one pipe nipple with a threaded connection to one drain trap from each of two instrument air receivers. The Preventive Maintenance Program will be enhanced to include activities to inspect the drain traps and the pipe nipple for the extended period of operation.

The staff determined that the enhancement to the Preventive Maintenance Program to include inspection of the drain trap and pipe nipple will provide an acceptable means of managing loss of material due to general corrosion for the carbon steel piping and fittings addressed in this AMR line item.

With regard to the Compressed Air Monitoring Program, the applicant stated that this program is not used at BSEP. The applicant's justification and the staff's evaluation are documented in the Audit and Review Report.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.2.2.1.4 Loss of Material for Carbon Steel Air Receivers in the HVAC Control Building System

In the discussion section of LRA Table 3.2.2-8, the applicant stated that it includes an AMR line item for air receivers (shell and access cover) in the HVAC control building system that are constructed of carbon steel and exposed to indoor air on their internal surfaces. The One-Time Inspection Program is specified to manage loss of material due to general corrosion for these components; however, GALL Report line item VII.D.3-a recommends the Compressed Air Monitoring Program to manage this aging effect. The staff asked the applicant to provide justification for using the One-Time Inspection Program to manage general corrosion on the interior surfaces of the air receivers instead of the Compressed Air Monitoring Program.

In its response, the applicant stated that this line item represents two air receivers in the HVAC control building system which receive dry, compressed air. Even though the inlet air is dried using an air dryer, any condensation is removed from the bottom of the tank through a piping and trap arrangement. The expectation is that these air receivers will not exhibit loss of material due to general corrosion. However, because the potential for condensation exists in the bottom of the tank, the two air receivers were conservatively assigned the aging effect of loss of material due to general corrosion.

The applicant also stated that the One-Time Inspection Program in the GALL Report is appropriate for the subject air receivers. The staff has accepted that a one-time inspection may be used to provide additional assurance that aging is not occurring or is so insignificant that an aging management program is not warranted. A one-time inspection may also trigger development of a program necessary to assure component intended functions through the period of extended operation. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that either verify that unacceptable degradation is not occurring, or trigger additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.

For aging management of the subject components, the One-Time Inspection Program will verify that the expectation is correct, or it will determine the extent of the degradation present so that corrective actions can be taken. The applicant stated that this is the approach used at BSEP and, based on the program description in the GALL Report, it is consistent with GALL Report recommendations. Since the piping components have a threaded connection, the air receiver inspections will likely be performed with the use of a boroscope or a volumetric examination, or a combination of the two techniques.

With regard to the Compressed Air Monitoring Program recommended in the GALL Report, the applicant stated in its response to the audit question that this AMP is not used at BSEP. The supply of dry instrument air to pneumatic controllers, dampers, and other pneumatic controls is provided by an air dryer located upstream of the devices served. The instrument air dryer is located downstream of the instrument air compressors. The compressed air is dried and cooled by a refrigerant type dryer. As documented in the Audit and Review Report, the applicant periodically tests the quality of the instrument air. This procedure is a result of the applicant’s response to GL 88-14, in which the applicant stated that they will maintain instrument air quality and to establish a program to include periodic sampling of the air quality of the instrument air system. Locations tested are monitored for dew point (each quarter), entrained particulates exceeding 3 microns (every 18 months), and hydrocarbon contaminates (every 18 months). The selected test locations provide a representative sample of the instrument air system, DG starting air system, and the HVAC control building system.

The applicant further stated in its response that, for the majority of the HVAC control building system instrument air components, loss of material was not identified as an aging effect for instrument air components subject to aging management based on the dry air delivered by the air dryer. Dry air is provided by system design, and is maintained by system operation and testing requirements as discussed above. Moisture downstream of the air dryer is controlled. BSEP currently uses procedures to test air quality periodically using representative samples, review trend data, and initiate corrective actions as appropriate for the instrument air system. BSEP has completed steps to test air quality periodically, review trend data, and initiate corrective actions as appropriate for the instrument air system and has met the intent of GL 88-14.

The applicant also provided copies of its bases documents as documented in the Audit and Review Report. The staff reviewed these documents and confirmed that, for the majority of the HVAC control building system instrument air components, dry air is provided by system design and is maintained by system operation and testing requirements to meet the intent of the compressed air monitoring system AMP recommended in the GALL Report.

The staff determined that, although the applicant has not credited an AMP consistent with the GALL Report, BSEP has procedures and programs in place that perform the activities included in the Compressed Air Monitoring Program recommended in the GALL Report. Therefore, the One-Time Inspection Program, together with the existing plant programs and procedures, meet the intent of the Compressed Air Monitoring Program. On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

<u>Conclusion</u>. The staff evaluated the applicant’s claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant’s consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

<u>Summary of Technical Information in the Application</u>. In LRA Section 3.2.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the ESF systems. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general corrosion
- local loss of material due to pitting and crevice corrosion
- local loss of material due to microbiologically influenced corrosion
- changes in properties due to elastomer degradation
- loss of material due to erosion of charging pump flow orifices
- buildup of deposits due to corrosion in drywell and torus spray nozzles and flow orifices

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.2.2.2. Details of the staff's audit are documented in the staff's Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

For some line-items assigned to the staff in LRA Tables 3.2.2-1 through 3.2.2-9, the GALL Report recommends further evaluation. When further evaluation is recommended, the staff reviewed these further evaluations provided in LRA Section 3.2.2.2 against the criteria provided in the SRP-LR Section 3.2.3.2. The staff's assessments of these evaluations is documented in this section. These assessments are applicable to each Table 2 line-item in Section 3.2 that cite the item in Table 1.

3.2.2.2.1 Cumulative Fatigue Damage

Cumulative fatigue is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in SER Section 4.3.

3.2.2.2.2 Loss of Material Due to General Corrosion

Areas with Stagnant Flow Conditions. The staff reviewed LRA Section 3.2.2.2.2.1 against the criteria in SRP-LR Section 3.2.2.2.2, which states:

> The management of loss of material due to general corrosion of pumps, valves, piping, and fittings associated with some of the BWR emergency core cooling systems [high pressure coolant injection, reactor core isolation cooling, high pressure core spray, low pressure core spray, low pressure coolant injection (residual heat removal)] and with lines to the suppression chamber and to the drywell and suppression chamber spray system should be further evaluated. The existing aging management program relies on monitoring and control of primary water chemistry based on BWRVIP 29 (EPRI TR-103515) for BWRs to mitigate degradation. However, control of primary water chemistry does not preclude loss of material due to general corrosion at locations of stagnant flow conditions. Therefore, verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general corrosion to verify the effectiveness of the chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.2.2.2.2.1, the applicant stated that loss of material due to general corrosion is predicted for carbon steel components exposed to treated water in the ECCS, and is managed by the Water Chemistry Program and the One-Time Inspection Program. The Water Chemistry Program manages aging effects through periodic monitoring and control of contaminants. Since control of water chemistry does not preclude corrosion at locations with stagnant flow conditions, the One-Time Inspection Program will provide a verification of the effectiveness of the Water Chemistry Program to manage loss of material due to general corrosion through examination of carbon steel ECCS components.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.2 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Interior and Exterior Surfaces of Carbon Steel Components</u>. The staff reviewed LRA Section 3.2.2.2.2.2 against the criteria in SRP-LR Section 3.2.2.2.2, which states:

> Loss of material due to general corrosion could occur in the drywell and suppression chamber spray (BWR) systems header and spray nozzle components, standby gas treatment system components (BWR), containment isolation valves and associated piping, the automatic depressurization system piping and fittings (BWR), emergency core cooling system header piping and fittings and spray nozzles (BWR), and the external surfaces of BWR carbon steel components. The GALL Report recommends further evaluation on a plant specific basis to ensure that the aging effect is adequately managed.

In LRA Section 3.2.2.2.2, the applicant stated that the Preventive Maintenance Program is used to manage loss of material due to general corrosion on interior surfaces of filter housings and ductwork in the standby gas treatment system. Loss of material due to external corrosion of carbon steel components is predicted by BSEP for components in air/gas environments exposed to moisture. To manage this aging effect/mechanism, the Systems Monitoring Program will be used. This program provides for scheduled visual inspections to ensure that aging degradation that might lead to loss of intended functions will be detected.

The staff noted that SRP-LR Section 3.2.2.2.2 requires aging management of several other components in the ESF systems, including the drywell and suppression chamber spray systems header and spray nozzle components, containment isolation valves and associated piping, and the automatic depressurization system piping and fittings and spray nozzles. These components are not addressed in the LRA.

The staff requested that the applicant explain how loss of material due to general corrosion on the interior surfaces of the aforementioned components would be managed.

As documented in the Audit and Review Report, the applicant provided the following further evaluations for each of the components identified:

> <u>Drywell and suppression chamber spray systems header</u>: The SRP-LR identifies loss of material due to general corrosion as a potentially applicable aging effect for the drywell and suppression chamber spray systems header. Aging management reviews have identified that carbon steel piping in normally wetted portions of these subsystems is susceptible to general corrosion, managed by the water chemistry program with a verification of program effectiveness using the One-Time Inspection Program. Regarding the portion of the Suppression Pool (Torus) Spray subsystem downstream of the isolation

valves, this piping is normally not wetted or pressurized, but rather exposed to the primary containment environment. Since the primary containment is inerted with nitrogen during operation, no significant corrosion of this piping is expected as a result. Similarly, drywell spray is considered an SR function, but is not expected to be used except in post accident conditions and the drywell spray headers are not subject to alternate wetting. This piping is assumed to be dry and normally exposed to the inerted drywell environment, and significant corrosion is not expected. Hence general corrosion of drywell and suppression chamber spray is not considered to be an aging mechanism requiring aging management.

The staff determined that the applicant’s evaluation for the drywell and suppression chamber spray systems header is acceptable on the basis that the wetted portion of the drywell and suppression chamber spray system header would be subject to loss of material due to general corrosion, and the Water Chemistry Program and One-Time Inspection Program specified by the applicant will adequately manage this aging effect. Further, the dry portion of the piping will not experience corrosion, and the applicant appropriately concluded that these components do not require aging management.

Drywell and suppression chamber spray systems spray nozzle components: As noted above, the suppression spray function is not safety-related at BSEP, hence, the suppression spray nozzles do not perform an intended function. Drywell spray is a safety-related function. The drywell spray nozzles are constructed of brass and installed in a normally dry, inerted environment. As such, they are not subject to general corrosion and aging management is not required.

The staff determined that the applicant’s justification for the drywell and supression chamber spray nozzle components not being subject to general corrosion is acceptable on the basis that the brass components will not experience any corrosion in a dry environment.

Containment isolation valves and associated piping: BSEP has not performed a separate aging management review of containment isolation valves and associated piping, but rather addressed aging management reviews of these components within the aging management reviews of the systems in which they occur. The BSEP methodology used for system aging management reviews conservatively predicts general corrosion in those applications where it might be applicable. Additional information regarding the aging management programs applied to manage general corrosion of containment isolation valves and associated piping is provided in line items for "Valves (including check valves and containment isolation) (body and bonnet)" in System AMR Tables 3.1.2, 3.2.2, 3.3.2 and 3.4.2.

The staff determined that the applicant’s approach for managing loss of material due to general corrosion in containment isolation valves and associated piping is acceptable on the basis that these components are addressed as part of the aging management review of the systems in which they are contained.

Automatic depressurization system piping and fittings and spray nozzles: BSEP includes the automatic depressurization system piping (S/RV downcomers) as part of the reactor vessel and internals system. Aging management review of these components are addressed in Section 3.1 of the LRA. These components are managed for general corrosion using the systems monitoring, water chemistry and one time inspection programs.

The staff determined that the applicant's approach for managing loss of material due to general corrosion in automatic depressurization system piping and fittings, and spray nozzles is acceptable on the basis that these components are addressed as part of the reactor vessel and internals system, and their aging management review is included in LRA Section 3.1.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.2 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.3 Local Loss of Material Due to Pitting and Crevice Corrosion

Areas with Stagnant Flow Conditions. The staff reviewed LRA Section 3.2.2.2.3.1 against the criteria in SRP-LR Section 3.2.2.2.3, which states:

> The management of local loss of material due to pitting and crevice corrosion of pumps, valves, piping, and fittings associated with some of the BWR emergency core cooling system piping and fittings [high pressure coolant injection, reactor core isolation cooling, high pressure core spray, low pressure core spray, low pressure coolant injection (residual heat removal)] and with lines to the suppression chamber and to the drywell and suppression chamber spray system should be evaluated further. The existing aging management program relies on monitoring and control of primary water chemistry based on EPRI guidelines of TR-105714 for PWRs and BWRVIP 29 (EPRI TR-103515) for BWRs to mitigate degradation. However, control of coolant water chemistry does not preclude loss of material due to crevice and pitting corrosion at locations of stagnant flow conditions. Therefore, verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage the loss of material due to pitting and crevice corrosion to verify the effectiveness of the chemistry control program). A onetime inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.2.2.2.3.1, the applicant stated that loss of material due to pitting and crevice corrosion is predicted for carbon steel components exposed to treated water in ECCS systems, and is managed by the Water Chemistry Program and the One-Time Inspection Program. The Water Chemistry Program manages aging effects through periodic monitoring and control of contaminants. Since control of water chemistry does not preclude corrosion at locations with stagnant flow conditions, the One-Time Inspection Program will provide a verification of the effectiveness of the Water Chemistry Program to manage loss of material due to pitting and crevice corrosion through examination of carbon steel ECCS components.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Interior and Exterior Surfaces of Carbon and Stainless Steel Components. The staff reviewed LRA Section 3.2.2.2.3.2 against the criteria in SRP-LR Section 3.2.2.2.3, which states:

> Local loss of material from pitting and crevice corrosion could occur in the containment isolation valves and associated piping, and automatic depressurization system piping and fittings (BWR). The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed.

In LRA Section 3.2.2.2.3.2, the applicant stated that the Preventive Maintenance Program is used to manage loss of material in filter housings and duct work in the standby gas treatment system. BSEP has addressed aging management of containment isolation valves and associated piping as a part of the system in which they reside. Generally, this entails use of the Systems Monitoring Program for exterior surfaces, and use of the Water Chemistry Program in conjunction with the One-Time Inspection Program on the internal surfaces.

The staff noted that LRA Section 3.2.2.2.3.2 does not address aging management of the ADS piping and fitting, as recommended by SRP-LR Section 3.2.2.2.3. The staff asked the applicant to explain how loss of material due to pitting and crevice corrosion in the ADS piping and fittings will be managed for the extended period of operation.

As documented in the Audit and Review Report, the applicant stated that BSEP includes the ADS piping (S/RV downcomers) as part of the reactor vessel and internals system. AMRs of these components are summarized LRA Section 3.1, and have identified pitting and crevice corrosion as being applicable to wetted portions of these components. These AMRs have specified the Water Chemistry Program for aging management, with program effectiveness verification performed under the One-Time Inspection Program.

The staff determined that the applicant’s approach for managing loss of material due to pitting and crevice corrosion in the ADS piping and fittings is acceptable on the basis that these components are included in the reactor vessel and internals system and their aging management is addressed as part of that system.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Local Loss of Material Due to Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.2.2.2.4 against the criteria in SRP-LR Section 3.2.2.2.4, which states:

> Local loss of material due to microbiologically influenced corrosion (MIC) could occur in BWR and PWR containment isolation valves and associated piping in systems that are not addressed in other chapters of the GALL Report. The GALL

> Report recommends further evaluation to ensure that the aging effect is adequately managed.

In LRA Section 3.2.2.2.4, the applicant stated that BSEP has addressed aging management of containment isolation valves and associated piping as a part of the system in which they reside. Generally, this entails use of the Systems Monitoring Program for the external surfaces, and use of the Water Chemistry Program in conjunction with the One-Time Inspection Program on the internal surfaces. BSEP has no service water lines inside the primary containment and MIC is not a significant liability for containment isolation components.

During the audit, the staff also interviewed the technical staff to determine which ESF components use service water for cooling and why MIC is not an issue for the containment isolation components. Based on the interview, it was determined that the RHR heat exchangers, ECCS pump coolers, and the RHR pump seals are among the ESF components that are cooled by service water. However, the containment isolation valves do not use service water for cooling; therefore, they are not subject to MIC. Based on the information provided, the staff determined that the applicant's further evaluation is acceptable since service water is not used to cool the containment isolation valves.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.4 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.5 Changes in Properties Due to Elastomer Degradation

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5, which states:

> Changes in properties due to elastomer degradation could occur in seals associated with the standby gas treatment system ductwork and filters. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed.

In LRA Section 3.2.2.2.5, the applicant stated that change in material properties (hardening, cracking) is predicted by the BSEP AMR methodology for elastomeric seals in the standby gas treatment system. The Preventive Maintenance Program will be used to manage aging of the internal surfaces of these seals; whereas, the Systems Monitoring Program will be used to manage aging of visible external surfaces.

The staff determined that the applicant's use of the Preventive Maintenance Program and Systems Monitoring Program are acceptable since they will periodically verify the condition of the elastomers and provide reasonable assurance that hardening and cracking are not occurring.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.5 for further evaluation. The staff also found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.6 Loss of Material Due to Erosion of Charging Pump Flow Orifices

This issue is applicable only to charging pumps in the chemical and volume control systems of PWRs.

3.2.2.2.7 Buildup of Deposits Due to Corrosion in Drywell and Torus Spray Nozzles and Flow Orifices

The staff reviewed LRA Section 3.2.2.2.7 against the criteria in SRP-LR Section 3.2.2.2.7, which states:

> The plugging of components due to general corrosion could occur in the spray nozzles and flow orifices of the drywell and suppression chamber spray system. This aging mechanism and effect will apply since the spray nozzles and flow orifices are occasionally wetted, even though the majority of the time this system is on standby. The wetting and drying of these components can aid in the acceleration of this particular corrosion. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed.

In LRA Section 3.2.2.2.7, the applicant stated that suppression pool (torus) spray is not required for design-basis accidents at BSEP, and is not considered an SR function. Drywell spray is required but not used in normal operation, and it is maintained isolated. Therefore, plugging or fouling of drywell spray components is not considered an applicable aging effect. Fouling of the ECCS strainers is managed by the Protective Coatings Monitoring and Maintenance Program, which ensures that failed coatings in the primary containment will not degrade the capability of ECCS systems, including RHR and drywell spray, below design requirements.

The staff noted that SRP-LR Section 3.2.2.2.7 states that wetting and drying of components due to their occasional use can aid in the acceleration of general corrosion, which may result in plugging of components in the drywell spray system. The staff asked the applicant to clarify why plugging of drywell spray components is not an applicable aging effect.

As documented in the Audit and Review Report, the applicant stated that drywell spray is an SR function, but this post-accident subsystem is not subject to alternate wetting either from normal operation or periodic flow testing. Moreover, the portion of the drywell spray subsystem downstream of isolation valves is normally exposed to the inerted primary containment environment. Therefore, significant accumulation of corrosion is not expected in the drywell spray header, and plugging or fouling of spray components is not considered to be an aging effect requiring aging management.

The staff determined that the applicant's justification for concluding that plugging is not an applicable aging effect for drywell spray nozzles and orifices is acceptable on the basis that these components are not subjected to alternate wetting and drying; therefore, they are not susceptible to corrosion product buildup, which could cause plugging.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.7 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant adequately addressed the issues that were further evaluated. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3 AMR Results That Are Not Consistent with or Are Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.2.2-1 through 3.2.2-10, the staff reviewed additional details of the results of the AMRs for material, environment, AERMs, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.2.2-1 through 3.2.2-10, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line-item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line-item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line-item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line-item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For the component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant’s evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff’s evaluation is discussed in the following sections.

3.2.2.3.1 Engineered Safety Features – Summary of Aging Management Evaluation – Residual Heat Removal (RHR) System – Table 3.2.2-1

The staff reviewed LRA Table 3.2.2-1, which summarizes the results of AMR evaluations for the RHR system component groups.

In LRA Section 3.2.2.1.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the RHR system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program

- Open-Cycle Cooling Water System Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program
- Preventive Maintenance Program

The staff reviewed the applicant's AMR of the RHR system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-1. The staff also reviewed those combinations in Table 3.2.2-1, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

<u>Aging Effects</u>. LRA Table 2.3.2-1 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for aging management review include piping and fitting, valves, pumps, heat exchangers, drywell and suppression chamber spray system, and pump suction strainers.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (includes steam)(internal) environments are subject to loss of material due to general, crevice, and pitting corrosion.
- Carbon steel components in treated water (internal) environments are subject to loss of material due to crevice, galvanic, general, and pitting corrosion.
- Carbon steel components in treated water (internal) environments are subject to flow blockage due to fouling, or loss of material due to erosion.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to loss of material due to crevice and pitting corrosion, and/or cracking due to SCC.
- Stainless steel components in treated water (internal) environments are subject to flow blockage due to fouling, and loss of material due to crevice and pitting corrosion and MIC.
- Stainless steel components in treated water (external) environments are subject to loss of material due to crevice and pitting corrosion.
- Stainless steel components in raw water (internal) environments are subject to loss of material due to crevice corrosion, pitting corrosion, and MIC, as well as loss of heat transfer effectiveness due to fouling of heat transfer surface. These components are also subject to flow blockage due to fouling.
- Copper-alloy components in treated water (external) or raw water environments are subject to loss of heat transfer effectiveness due to fouling of heat transfer surfaces.
- Copper-alloy components in treated water (external) environments are subject to loss of material due to crevice and pitting corrosion, or loss of material due to selective leaching.

- Copper-alloy components in raw water (internal) environments are subject to loss of material due to erosion and/or galvanic corrosion.
- Copper-alloy components in raw water (internal) environments are subject to loss of material due to erosion and MIC.
- Copper-alloy components in indoor air (external) environments are subject to loss of heat transfer effectiveness due to fouling of heat transfer surfaces.
- Grey cast iron components in treated water (internal) environments are subject to loss of material due to galvanic corrosion, loss of material due to selective leaching, or loss of material due to crevice, general, and pitting corrosion.
- Stainless steel components in indoor air (external) environments are not identified with any aging effects.
- Thermal insulation (such as glass fiber or calcium silicate) in indoor (external) environments are not identified with any aging effects.
- Carbon steel components in dry air/gas (internal) environments are not identified with any aging effects.

During its review, the staff determined that it needed additional information to complete its review. The specific RAI and the applicant's response are discussed below.

In LRA Tables 3.2.2-1, 3.2.2-3, 3.2.2-5, and 3.2.2-7, carbon steel and stainless steel piping/fittings, valves, and small-bore piping in treated water (includes steam) (internal) environments are subject to loss of material due to crevice, general, and pitting corrosion. The Section XI Inservice Inspection and Water Chemistry Programs are credited to manage the aging effect. In draft RAI 3.2-8, dated February 2, 2005, the staff requested the applicant to explain how the Section XI ISI Program will be used to manage the above identified aging effect of loss of material in the specified internal environment, noting that the ISI program is primarily credited for managing the aging effect of cracking. During a teleconference held on June 29, 2005, the applicant responded by stating that portions of the systems involved are included in Section XI ISI Class 1 boundaries, and that the piping represented by the respective AMR line items are subject to Section XI ISI Class 1 examination requirements. The examination includes volumetric examinations, which would be effective in detecting the loss of material due to crevice, general, and pitting corrosion. The staff considered the applicant's response to be insufficient in demonstrating the effectiveness of the ISI program in managing loss of material due to crevice, general, and pitting corrosion, for the inside surfaces of piping components. The staff requested the applicant to address five follow-up questions:

(1) Provide the basis for concluding that the potential for internal corrosion is the greatest at Class 1 ISI welds due to sensitization and geometric changes associated with the weldment.

(2) The GALL ISI Program does not specifically call for inspections at other susceptible internal surfaces of piping and fittings.

(3) The ability of volumetric examination methods (UT and radiographic testing (RT)) to detect loss of material for internal surfaces needs to be assured for the system components in question.

(4) An augmented inspection program should be required to verify the effectiveness of the Water Chemistry Program and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

(5) Both Class 1 boundaries and those outside of Class 1 boundaries need to be addressed.

By letter dated July 18, 2005, in the supplemental response to RAI 3.3.2-1-2, the applicant provided its responses to the above follow-up questions.

Regarding Follow-up Question 1, the applicant stated that the scope of Section XI ISI is not limited to weldments; rather, weldments are generally specified as inspection locations on the basis of susceptibility. Welds are typically specified for inspection because the assessment of degradation mechanisms identifies them as the areas of most concern. This increased susceptibility at welds is attributed to metallurgical changes and surface imperfections associated with the welding process. The applicant provided a detailed discussion, contained in the American Society for Metals Handbook, Volume 13, pertaining to crevice and pitting corrosion of the heat-affected zone of weldments. The applicant also stated that the handbook contains a similar discussion of the potential for sensitization at weldments of stainless steels and nickel-based alloys. While measures can be specified to minimize the potential for corrosion in welds, the applicant stated that the variables associated with welding activities introduce a set of liabilities to welds not applicable to the balance of piping base metal. The staff determined that the applicant adequately explained the basis of increased susceptibility at welds, and assured an inspection scope of Section XI ISI Program beyond weldments. Follow-up Question 1 is, therefore, closed.

Regarding Follow-up Question 2, the applicant stated that the current approved version of GALL Report, Section XI ISI Program does not specifically address crevice, pitting, and general corrosion of other susceptible internal surfaces of Class 1 piping. This is because the industry has been effective in mitigating these aging mechanisms with water chemistry. These mechanisms, where applicable, were being included in the LRA due to the conservative, deterministic methods being used in AMRs; namely, assuming no water chemistry controls. The staff found the applicant's explanation to be acceptable, and Follow-up Question 2 is closed.

Regarding Follow-up Question 3, the applicant stated that, consistent with EPRI guidance, and as approved by the staff, the RI-ISI methodology includes: (1) identification and evaluation of potentially active degradation mechanisms, (2) selection of inspection locations in which the impact of each degradation mechanism is most severe, and (3) implementation of appropriate inspection methods, such as UT or RT, with qualified inspectors. The applicant stated that the assessment of applicable degradation mechanisms is piping/component-specific, and includes consideration of a range of factors including materials, pipe size/schedule, component type, geometry/configuration, fabrication methods, operating conditions, and service experience. The type of inspections, area to be examined, and qualification requirements for inspection personnel are specific to the degradation mechanism of concern.

In addition, the applicant stated that the types of flaws required to be detected under Section XI, Subsection IWB, are not limited to cracks, but include other types of imperfections and inclusions meeting the flaw-size criteria of IWB-3500. Qualification requirements for personnel performing volumetric examinations are intended to assure the inspection would find minor surface imperfections on the inside of piping geometries, consistent with the flaw-size requirements and acceptance criteria of the ASME Code. The staff found the applicant's response to have adequately addressed its concern regarding the ability of volumetric examination methods in detecting loss of material at the inside surface of piping components. Follow-up Question 3 is, therefore, closed.

Regarding Follow-up Question 4, the applicant stated that an augmented inspection is not needed to address the potential for loss of material due to crevice, pitting, or general corrosion of Class 1 piping. As prescribed by 10 CFR 50.55a, Section XI ISI requirements, and NRC-approved alternatives such as RI-ISI, are not limited to detection of cracking, but also include detection of loss of material due to crevice, pitting, and general corrosion. The applicant stated that the same Section XI ISI program that ensures an acceptable level of quality and safety during the current licensing period will continue in that role during the period of extended operation. The staff found the applicant’s response to be adequate to assure that an augmented inspection program, other than the Section XI ISI Program, will not be needed for the verification of the effectiveness of the Water Chemistry Program. Follow-up Question 4 is, therefore, closed.

Regarding Follow-up Question 5, the applicant stated that the line items addressed in this discussion pertain only to NPS-4 Class 1 piping and larger. Components outside of Class 1 boundaries which credit the Water Chemistry Program for aging management are subject to the One-Time Inspection Program for verification of program effectiveness, consistent with GALL. It is noted that GALL does not specify one-time inspections for Class 1 piping that is NPS-4 and larger, because it is subject to volumetric examination. Less than NPS-4 Class 1 piping is not subject to volumetric examination, and has been included in the One-Time Inspection Program. The staff found the applicant’s response to have adequately delineated the AMRs for both Class 1 boundaries and those outside of Class 1 boundaries, including pipes of different sizes. Follow-up Question 5 is, therefore, closed.

Based on the applicant’s satisfactory responses to the staff follow-up questions, as discussed above, RAI 3.2-8 is resolved.

In RAI 3.2-1, dated April 8, 2005, the staff stated that in LRA Table 3.2.2-1, carbon steel spray nozzles in the drywell and suppression chamber spray system, in a dry air/gas (internal) environment, are not identified with any aging effects. The applicant stated that the basis is that “Suppression pool spray is not required for design basis events. Drywell spray nozzles/piping is required but is normally isolated and not subject to plugging or fouling.” Therefore, the staff requested that the applicant explain why the suppression pool spray is not required for design-basis events (DBEs). Noting that industry operating experience has revealed that plugging or fouling of carbon steel spray nozzles could occur if not properly prevented or managed, the staff also requested the applicant to provide the necessary procedure to ensure that drywell spray nozzles/piping will be free from plugging. In its response, by letter dated May 4, 2005, the applicant stated that the drywell and suppression pool spray subsystems are provided to condense steam and cool non-condensable gases in reducing containment pressure and temperature after a loss of coolant accident (LOCA). Analyses performed in support of the BSEP EPU submittal credit containment (i.e., drywell) spray with maintaining the drywell temperature profile within EQ requirements subsequent to small steamline breaks. The applicant stated that, otherwise, neither drywell nor suppression pool spray is needed to maintain post-accident primary containment P-T parameters within acceptable values.

The applicant further stated that the assumption that drywell spray nozzle and piping are free from plugging is not based on procedural requirements, but rather on consideration that drywell spray components are not intermittently wetted, that the drywell is inerted with nitrogen during operation, and that the spray nozzles themselves are constructed of corrosion-resistant material (brass). The applicant stated that the industry operating experience discussed in SRP-LR Section 3.2.2.7, pertains to spray piping that is subject to alternate wetting, and is not applicable to drywell spray components at BSEP. Drywell spray is a post-accident function at BSEP. It is not actuated during the course of normal plant operations, and UFSAR 5.4.7.4 notes that operation of valves to the containment spray headers is checked by operating the upstream and downstream valves individually, thereby avoiding initiating spray during routine testing.

The staff found the above responses provided by the applicant to be adequate in explaining why the carbon steel spray nozzles in the drywell and suppression chamber spray system are not identified with any aging effects. Therefore, the staff's concern described in RAI 3.2-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the RHR system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the components in the RHR system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.2.2-1 identifies the following AMPs for managing the aging effects described above for the RHR system:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- Open-Cycle Cooling Water System Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program
- Preventive Maintenance Program

SER Sections 3.0.3.1.1, 3.0.3.2.1, 3.0.3.1.3, 3.0.3.2.4, 3.0.3.2.11, 3.0.3.2.12, 3.0.3.2.18, 3.0.3.1.2, and 3.0.3.3.3, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant described appropriate AMPs for managing the aging effects of the RHR system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.2.2.3.2 Engineered Safety Features – Summary of Aging Management Evaluation – Containment Atmosphere Control (CAC) System – Table 3.2.2-2

The staff reviewed LRA Table 3.2.2-2, which summarizes the results of AMR evaluations for the CAC system component groups.

In LRA Section 3.2.2.1.2, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the CAC system components:

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

The technical staff reviewed the applicant's AMR of the CAC system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-2. The staff also reviewed those combinations in LRA Table 3.2.2-2, with Notes A through E, for which issues were identified. The staff determined that the applicant identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-2 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for aging management review include: piping and fitting, valves, tanks, pumps, and heat exchangers.

- For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in indoor air (internal) environments are subject to loss of material due to general corrosion.
- Stainless steel components in treated water (internal or external) environments are subject to loss of material due to crevice and pitting corrosion.
- Carbon steel components in dry air/gas (internal) environments are not identified with any aging effects.
- Stainless steel components in dry air/gas (internal) or indoor air (external) environments are not identified with any aging effects.
- Copper-alloy components in dry air/gas (internal) or indoor air (internal or external) environments are not identified with any aging effects.
- Glass components in indoor air (external) or treated water (internal) environments are not identified with any aging effects.

During its review, the staff determined that it needed additional information to complete its review. The specific RAIs and the applicant's responses are discussed below.

In RAI 3.2-2, dated April 8, 2005, the staff stated that in LRA Table 3.2.2-2, no aging effects are identified for glass components in a treated water (internal) environment. Therefore, the staff requested that the applicant provide the basis for such determination. In its response, by letter dated May 4, 2005, the applicant stated that because most silicate glasses have a high resistance to corrosion in normal environments, glass *per se* is frequently considered to be an inert substance. Silica is almost insoluble in an aqueous environment, except at temperatures above 482EF. Acid attack of soda-lime and bororsilicate glass compositions is minimal due to the formation of a protective, highly siliceous surface layer, except for hydrofluoric and phosphoric (i.e., at high temperatures) acids. The applicant stated that indoor and outdoor environments do not typically contain contaminants that could concentrate and chemically attack glass. Based on this information, and the fact that no definitive instances of glass failure due to aging have been identified in industry operating experience searches, the staff considered the applicant's basis for concluding that no aging effects are predicted for glass components in the CAC system to be acceptable. Therefore, the staff's concern described in RAI 3.2-2 is resolved.

In RAI 3.2-3, dated April 8, 2005, the staff stated that in LRA Table 3.2.2-2, for the stainless steel heat exchangers in dry air/gas (internal) environments, the applicant stated under Note 208 that "Heat exchangers in this category are in scope for spatial interaction with SR components. Therefore, only the external surfaces require aging management review." Therefore, the staff requested that the applicant clarify the meaning of this statement, and explain how the aging management for the "spatial interaction" of the stainless steel components is to be performed. In its response, by letter dated May 4, 2005, the applicant stated that "spatial interaction" in the context of Note 208 means the potential to spray, wet, or otherwise adversely affect the function of SR equipment. In this instance, the heat exchangers are sample precoolers, which are literally coils in an air environment. The applicant stated that since the application does not involve liquid-filled components, Note 208 was misapplied. Instead, Notes 221 and 215 are applicable, and no aging effects are predicted. The staff found the applicant's resolution of the above misapplication to be acceptable. Therefore, the staff's concern described in RAI 3.2-3 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the CAC system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CAC system.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program, in accordance with 10 CFR 54.21(d)

LRA Table 3.2.2-2 identifies the following AMPs for managing the aging effects described above for the CAC system:

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

SER Sections 3.0.3.2.1, 3.0.3.2.11, and 3.0.3.3.2, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant described the appropriate AMPs for managing the aging effects of the CAC system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.2.2.3.3 Engineered Safety Features – Summary of Aging Management Evaluation – High Pressure Coolant Injection (HPCI) System – Table 3.2.2-3

The staff reviewed LRA Table 3.2.2-3, which summarizes the results of AMR evaluations for the HPCI system component groups.

In LRA Section 3.2.2.1.3, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the HPCI system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Control Program
- One-Time Inspection Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program
- Preventive Maintenance Program

The technical staff reviewed the applicant's AMR of the HPCI system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-3. The staff also reviewed those combinations in Table 3.2.2-3, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-3 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include: piping and fittings, pumps, valves, tanks, steam turbines, strainer elements, and heat exchangers.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (includes steam)(internal), or treated water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion.

- Carbon steel components in treated water (internal) environments are subject to general, crevice, pitting, and galvanic corrosion.
- Carbon steel components in treated water (internal) are subject to flow blockage due to fouling.
- Carbon steel components in treated water (includes steam)(internal) environments are subject to cracking due to thermal and mechanical loadings.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion.
- Stainless steel components in treated water (includes steam)(internal), or treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion.
- Stainless steel components in treated water (internal) are subject to flow blockage due to fouling.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to thermal and mechanical loadings.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to loss of material due to flow-accelerated corrosion.
- Strainer elements in lube oil (internal) or treated water (internal) environments are subject to flow blockage due to fouling.
- Carbon steel components in indoor air (external) or lube oil (internal) environments are not identified with any AERMs.
- Stainless steel components in indoor air (external), dry air/gas (internal), or lube oil (internal) environments are not identified with any AERMs.
- Insulation material in indoor air (external) environments are not identified with any AERMs.
- Copper-alloy components in lube oil (internal or external) environments are not identified with any AERMs.

During its review, the staff determined that it needed additional information to complete its review. The specific RAI and the applicant's response are discussed below.

In LRA Table 3.2.2-3, carbon steel piping/fittings, valves, and small-bore piping in treated water (includes steam) (internal) environments are subject to loss of material due to crevice, general, and pitting corrosion. The Section XI ISI and Water Chemistry Programs are credited to manage the aging effect. In RAI 3.2-8, the staff requested the applicant to explain how the Section XI ISI program will be used to manage the above identified aging effect of loss of material in the specified internal environment, noting that the ISI program is primarily credited for managing the aging effect of cracking. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.2.2.3.1.

In RAI 3.2-4, dated, April 8, 2005, the staff stated that in LRA Tables 3.2.2-3, 3.2.2-5, and 3.2.2-7, carbon and stainless steel small-bore piping and fittings less than NPS-4, in treated water (includes steam)(internal) environments, are subject to cracking due to thermal and mechanical loading. The Section XI Inservice Inspection and Water Chemistry Programs are credited to manage the identified aging effect. In the subject tables, stainless steel small-bore piping less than NPS-4, in the same treated water (includes steam)(internal) environment, are also subject to cracking due to SCC. The same AMPs are credited to manage the aging effect. Therefore, the staff requested that the applicant (1) provide the basis for the statement made under Note 226 that “cracking due to thermal and mechanical loadings was evaluated and dispositioned as not applicable,” and (2) clarify the statement made under Note 226 that “The risk associated with cracking due to SCC is bounded by those components selected for inservice inspection as part of the Risk-Informed ISI Program...”

In its response, by letter dated May 4, 2005, the applicant stated that susceptibility to cracking due to thermal and mechanical loading has been previously evaluated on a component-specific basis, in support of the BSEP RI-ISI submittal in PEC letter to the NRC (serial: BSEP 01-0013) dated April 20, 2001. However, the applicant also stated that BSEP has revised its aging management strategy for small-bore piping to include a one-time inspection in response to NRC comments during an audit of AMPs, and it no longer credits RI-ISI in aging management. The applicant credits the Water Chemistry Program and ASME Section XI Subsection IWB, IWC and IWD Program for aging management of cracking, including SCC, in less than NPS-4 Class 1 piping components. The applicant stated that, consistent with the GALL Report, the One-Time Inspection Program will be used to verify the effectiveness of these programs. SER Section 3.0.3.2.11 provides the staff’s discussion of the applicant’s One-Time Inspection Program. It is noted that in its response to Audit Question B.2.15-1a, the applicant stated that in LRA Tables 3.2.2-3, 3.2.2-5, and 3.2.2-7, the AMR line items addressing small-bore Class 1 piping will be revised to reflect Water Chemistry, ASME Section XI Subsection IWB, IWC and IWD, and One-Time Inspection Programs for aging management of cracking due to thermal and mechanical loading and SCC. In addition, the applicant noted that Note 226 is no longer applicable.

Based on the above information provided by the applicant, the staff considered that the applicant adequately clarified the aging management for small-bore Class 1 piping components, which are susceptible to cracking due to thermal and mechanical loading and SCC. Therefore, the staff’s concern described in RAI 3.2-4 is resolved.

In RAI 3.2-5, dated April 8, 2005, the staff stated that in LRA Table 3.2.2-3, stainless steel piping and fittings (HPCI) in treated water (includes steam)(internal) environments are subject to cracking due to SCC. The Water Chemistry and One-Time Inspection Programs are credited to manage the aging effect. The staff noted the statement made in LRA Section B.2.15 by the applicant that “BSEP does not utilize the One-Time Inspection Program activity specified in the GALL Report, for detection of cracking in small-bore Class 1 piping. Cracking of this piping will be detected and managed by the combination of the ASME Section XI, Subsection IWB, IWC, and IWD Program supplemented by the Water Chemistry Program...” Therefore, the staff requested that the applicant clarify the discrepancy found between the above statement and the LRA Table 3.2.2-3 . In its response, by letter dated May 4, 2005, the applicant stated that BSEP has revised its aging management strategy for small-bore piping for consistency with the GALL Report. The applicant credits a combination of the Water Chemistry Program, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program, and the One-Time Inspection Program for managing cracking of small-bore piping, consistent with the recommendations of GALL IV.C1.1.13. See the staff’s discussion on the applicant’s responses to RAI 3.2-4 and Audit Question B.2.15-1a for additional information. The staff found the applicant’s responses to be acceptable, and RAI 3.2-5 is, therefore, resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the HPCI system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the components in the HPCI system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.2.2-3 identifies the following AMPs for managing the aging effects described above for the HPCI system:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Control Program
- One-Time Inspection Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program
- Preventive Maintenance Program

Sections 3.0.3.1.1, 3.0.3.2.1, 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.11, 3.0.3.2.18, 3.0.3.3.2, and 3.0.3.3.3 of this SER, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the HPCI system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.2.2.3.4 Engineered Safety Features – Summary of Aging Management Evaluation – Automatic Depressurization System (ADS) – Table 3.2.2-4

The staff reviewed LRA Table 3.2.2-4, which summarizes the results of AMR evaluations for the ADS component groups.

In LRA Section 3.2.2.1.4, the applicant identified the materials and environments for the components in the ADS, and identified no AERMs. No AMPs were, therefore, required for the ADS system components.

The technical staff reviewed the applicant's AMR of the ADS system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-4. The staff also reviewed those combinations in Table 3.2.2-4, with Notes A through E, for which issues were identified. The staff determined whether the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs, if credited, to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-4 lists individual system components within the scope of license renewal and subject to an AMR. Valves are the only components that do not rely on the GALL Report for AMR.

For this component type, the applicant identified the materials, environments, and AERMs, as specified below:

- Stainless steel components in dry air/gas (internal) environments are not identified with any AERMs.
- Stainless steel components in indoor air (external) environments are not identified with any AERMs.

On the basis of its review of the information provided in the LRA, the staff found that the absence of aging effects for the ADS system component type not addressed by the GALL Report is consistent with industry experience for these combinations of material and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant adequately concluded that there are no AERMs for the materials and environments associated with the components in the ADS system.

Aging Management Programs. Because there are no AERMs, no AMPs are required for the ADS system.

3.2.2.3.5 Engineered Safety Features – Summary of Aging Management Evaluation – Core Spray (CS) System – Table 3.2.2-5

The staff reviewed LRA Table 3.2.2-5, which summarizes the results of AMR evaluations for the CS system component groups.

In LRA Section 3.2.2.1.5, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the CS system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- One-Time Inspection Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program

In LRA Table 3.2.2-5, the applicant provided a summary of the AMRs for the CS system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant’s AMR of the CS system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-5. The staff also reviewed those combinations in Table 3.2.2-5, with Notes A through E, for which issues were identified. The staff determined that the applicant identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-5 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include: piping and fitting, valves, pumps, and pump suction strainers

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (includes steam)(internal) or treated water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion.
- Carbon steel components in treated water (internal) environments are subject to loss of material due to crevice, galvanic, general, and pitting corrosion.
- Carbon steel components in treated water (internal) environments are subject to flow blockage due to fouling.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to loss of material due to crevice and pitting corrosion, or cracking due to thermal and mechanical loading.
- Stainless steel components in treated water (internal) environments are subject to flow blockage due to fouling, and loss of material due to crevice and pitting corrosion.
- Carbon steel components (external surfaces) in indoor air (external) environments are subject to loss of material due to general corrosion.
- Stainless steel components in indoor air (external) environments are not identified with any AERMs.

During its review, the staff determined that it needed additional information to complete its review. The specific RAIs and the applicant's responses are discussed below.

In LRA Table 3.2.2-5, carbon steel piping/fittings, valves, and small-bore piping in treated water (includes steam) (internal) environments are subject to loss of material due to crevice, general, and pitting corrosion. The Section XI Inservice Inspection and Water Chemistry Programs are credited to manage the aging effect. In RAI 3.2-8, the staff requested the applicant to explain how the Section XI ISI Program will be used to manage the above identified aging effect of loss of material in the specified internal environment, noting that the ISI Program is primarily credited for managing the aging effect of cracking. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.2.2.3.1.

In LRA Table 3.2.2-5, carbon and stainless steel small-bore piping and fittings less than NPS-4 in treated water (includes steam)(internal) environments, are subject to cracking due to thermal and mechanical loading. The Section XI Inservice Inspection and Water Chemistry Programs are credited to manage the identified aging effect. In the subject tables, stainless steel small-bore piping less than NPS-4, in the same treated water (includes steam)(internal) environment, are also subject to cracking due to SCC. The same AMPs are credited to manage the aging effect. In RAI 3.2-4, the staff requested the applicant to (1) provide the basis for the statement made under Note 226 that “cracking due to thermal and mechanical loadings was evaluated and dispositioned as not applicable,” and (2) clarify the statement made under Note 226 that “The risk associated with cracking due to SCC is bounded by those components selected for inservice inspection as part of the Risk-Informed ISI Program...” SER Section 3.2.2.3.3 provides the staff’s discussion of this RAI and its resolution by the applicant.

In RAI 3.2-6, dated April 8, 2005, the staff stated that in LRA Table 3.2.2-5, carbon steel piping and fittings (misc. auxiliary and drain piping and valves) in treated water (internal) environments are subject to loss of material due to crevice, general, and pitting corrosion. The One-Time Inspection Program is credited to manage the aging effects. The applicant’s Note 205 states that “The One-Time Inspection Program will include elements to verify the integrity of spatial interaction piping.” Therefore, the staff requested that the applicant explain how this note is applicable to the aging effects identified. The applicant was also requested to provide the basis of using the One-Time Inspection Program alone to manage the identified aging effects without the use of the Water Chemistry Program. In its response, by letter dated May 4, 2005, the applicant stated that the subject line item should reflect Water Chemistry and One-Time Inspection Programs for aging Management. The applicant stated that the AMR is being revised to apply these two programs consistent with comparable line items in the RHR, HPCI, and RCIC systems. This is acceptable to the staff, and the concern described in RAI 3.2-6 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s responses to the above RAIs, the staff found that the aging effects of the CS system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CS system.

<u>Aging Management Programs</u>. After evaluating the applicant’s identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.2.2-5 identifies the following AMPs for managing the aging effects described above for the CS system:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- One-Time Inspection Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program

SER Sections 3.0.3.1.1, 3.0.3.2.1, 3.0.3.1.3, 3.0.3.2.11, 3.0.3.2.18, and 3.0.3.3.2, respectively, present the staff’s detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the CS system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.2.2.3.6 Engineered Safety Features – Summary of Aging Management Evaluation - Standby Gas Treatment System (SGTS) – Table 3.2.2-6

The staff reviewed LRA Table 3.2.2-6, which summarizes the results of AMR evaluations for the SGTS component groups.

In LRA Section 3.2.2.1.6, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the SGTS components:

- One-Time Inspection Program
- Buried Piping and Tanks Inspection Program
- Systems Monitoring Program
- Preventive Maintenance Program

The technical staff reviewed the applicant's AMR of the SGTS system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-6. The staff also reviewed those combinations in Table 3.2.2-6, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

<u>Aging Effects</u>. LRA Table 2.3.2-6 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include piping specialties and instrument tubing.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in indoor air (internal) environments are subject to loss of material due to general corrosion.
- Carbon steel components in buried (external) environments are subject to loss of material due to crevice, general, and pitting corrosion, as well as MIC.
- Elastomer components in indoor air (internal or external) environments are subject to loss of material due to wear.
- Stainless steel components in indoor air (internal or external) environments are not identified with any AERMs.

On the basis of its review of the information provided in the LRA, the staff found that the aging effects of the SGTS component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the components in the SGTS system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.2.2-6 identifies the following AMPs for managing the aging effects described above for the SGTS system:

- One-Time Inspection Program
- Buried Piping and Tanks Inspection Program
- Systems Monitoring Program
- Preventive Maintenance Program

SER Sections 3.0.3.2.11, 3.0.3.2.13, 3.0.3.3.2, and 3.0.3.3.3, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the SGTS system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.2.2.3.7 Engineered Safety Features – Summary of Aging Management Evaluation – Standby Liquid Control (SLC) System – Table 3.2.2-7

The staff reviewed LRA Table 3.2.2-7, which summarizes the results of AMR evaluations for the SLC system component groups.

In LRA Section 3.2.2.1.7, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the SLC system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- One-Time Inspection Program
- Systems Monitoring Program
- Preventive Maintenance Program

The technical staff reviewed the applicant's AMR of the SLC system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-7. The staff also reviewed those combinations in Table 3.2.2-7, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-7 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include: piping and fitting, valves, tanks, and pumps.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (internal) environments are subject to loss of material due to crevice, galvanic, general, and pitting corrosion.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to loss of material due to crevice and pitting corrosion, or cracking due to thermal and mechanical loading.
- Stainless steel components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion.
- Plastics/polymer components in indoor air (internal) environments are subject to cracking due to various degradation mechanisms.
- Plastics/polymer components in treated water (external) environments are subject to change in material properties due to various degradation mechanisms.
- Stainless steel components in indoor air (external) environments are not identified with any AERMs.
- Glass components in indoor air (external) or treated water (internal) environments are not identified with any AERMs.

During its review, the staff determined that it needed additional information to complete its review. The specific RAIs and the applicant's responses are discussed below.

In LRA Table 3.2.2-7, stainless steel piping/fittings, valves, and small-bore piping in treated water (includes steam) (internal) environments are subject to loss of material due to crevice and pitting corrosion. The Section XI Inservice Inspection and Water Chemistry Programs are credited to manage the aging effect. In RAI 3.2-8, the staff requested the applicant to explain how the Section XI ISI program will be used to manage the above identified aging effect of loss of material in the specified internal environment, noting that the ISI program is primarily credited for managing the aging effect of cracking. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.2.2.3.1.

In LRA Table 3.2.2-7, no aging effects are identified for glass components in a treated water (internal) environment. In RAI 3.2-2, the staff requested the applicant to provide the basis for such determination. SER Section 3.2.2.3.2 provides the staff's discussion of this RAI and its resolution by the applicant.

In RAI 3.2-7, dated April 8, 2005, the staff stated that in LRA Table 3.2.2-7, carbon steel components in treated water (internal) environments is subject to loss of material due to crevice, general, and pitting corrosion. The Preventive Maintenance Program is credited to manage the aging effects. The applicant's Note 206 to LRA Tables 3.2.2-1 through 3.2.2-9, states that "Internal inspection of the phenolic-lined carbon steel accumulator tank is performed under the Preventive Maintenance Program." Therefore, the staff requested that the applicant provide the basis for crediting the Preventive Maintenance Program to manage the identified aging effects, in lieu of the Water Chemistry and One-Time Inspection Programs. In its response, by letter dated May 4, 2005, the applicant stated that the Preventive Maintenance Program is directed at defined inspections of specific components. The SLC hydraulic accumulators are carbon steel tanks lined internally with a phenolic coating, containing a rubber bladder charged with nitrogen. BSEP has existing preventive maintenance routes to internally inspect these accumulators to verify the integrity of the rubber bladder, the condition of the phenolic coating, and any corrosion occurring on the interior surfaces of the carbon steel tanks. The applicant stated that these activities provide direct verification on an ongoing basis that aging effects are not occurring. The staff found the applicant's response to be adequate in explaining how the interior surfaces of the SLC hydraulic accumulator tanks are inspected, using the existing Preventive Maintenance Program, to preclude corrosion from occurring. Therefore, the staff's concern described in RAI 3.2-7 is, resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the SLC system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the SLC system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.2.2-7 identifies the following AMPs for managing the aging effects described above for the SLC system:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- One-Time Inspection Program
- Systems Monitoring Program
- Preventive Maintenance Program

Sections 3.0.3.1.1, 3.0.3.2.1, 3.0.3.1.3, 3.0.3.2.11, 3.0.3.3.2, and 3.0.3.3.3 of this SER, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant described appropriate AMPs for managing the aging effect of the SLC system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable, in accordance with 10 CFR 54.21(d).

3.2.2.3.8 Engineered Safety Features – Summary of Aging Management Evaluation – HVAC Control Building System – Table 3.2.2-8

The staff reviewed LRA Table 3.2.2-8, which summarizes the results of AMR evaluations for the HVAC control building system component groups.

In LRA Section 3.2.2.1.8, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the HVAC control building system components:

- One-Time Inspection Program
- Systems Monitoring Program
- Preventive Maintenance Program

In LRA Table 3.2.2-8, the applicant provided a summary of the AMRs for the HVAC control building system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the HVAC control building system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-8. The staff also reviewed those combinations in Table 3.2.2-8, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-8 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include piping and fittings, valves, air receivers, filters, dryers, ducts, and heating/cooling coils.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel and carbon steel - galvanized components in indoor air (internal) environments are subject to loss of material due to general corrosion.
- Carbon steel components in outdoor air (internal or external) environments are subject to loss of material due to general corrosion.
- Carbon steel - galvanized components in outdoor air (internal) environments are subject to loss of material due to aggressive chemical attack and loss of material due to general corrosion.
- Stainless steel components in indoor air (internal) environments are subject to loss of material due to crevice and pitting corrosion.
- Plastics/polymer components in indoor air (internal or external) environments are subject to cracking due to various degradation mechanisms.
- Elastomer components in indoor air (internal) environments are subject to cracking due to various degradation mechanisms and/or loss of material due to wear.
- Copper-alloy components in indoor air (external) environments are subject to loss of material due to crevice and pitting corrosion.

- Copper-alloy and aluminum-alloy components in indoor air (external) or outdoor air (external) are subject to loss of heat transfer effectiveness due to fouling of heat transfer surfaces.
- Stainless steel, copper-alloy, glass, and aluminum-alloy components in dry air/gas (internal) environments are not identified with any aging effects.
- Stainless steel, carbon steel - galvanized, and copper-alloy components in indoor air (internal) environments are not identified with any AERMs.
- Stainless steel, carbon steel - galvanized, copper-alloy, glass, insulation, and aluminum-alloy components in indoor air (external) environments are not identified with any AERMs.

On the basis of its review of the information provided in the LRA, the staff found that the aging effects of the HVAC control building system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the components in the HVAC control building system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.2.2-8 identifies the following AMPs for managing the aging effects described above for the HVAC control building system:

- One-Time Inspection Program
- Systems Monitoring Program
- Preventive Maintenance Program

SER Sections 3.0.3.2.11, 3.0.3.3.2, and 3.0.3.3.3, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant described appropriate AMPs for managing the aging effect of the HVAC control building system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.2.2.3.9 Engineered Safety Features – Summary of Aging Management Evaluation – Reactor Protection System – Table 3.2.2-9

The staff reviewed LRA Table 3.2.2-9, which summarizes the results of AMR evaluations for the reactor protection system component groups.

In LRA Section 3.2.2.1.9, the applicant identified the materials and environments for the components in the reactor protection system, and identified no AERMs. Therefore, no AMPs were required for the reactor protection system components.

The technical staff reviewed the applicant's AMR of the reactor protection system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.2.2-9. The staff also reviewed those combinations in LRA Table 3.2.2-9, with Notes A through E, for which issues were identified. The staff determined whether the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs, if credited, to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.2-9 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include miscellaneous components in ESFs.

For this component type, the applicant identified the material, environment, and AERM, as specified below:

- Stainless steel components in indoor air (internal or external) environments are not identified with any AERMs.

On the basis of its review of the information provided in the LRA, the staff found the absence of aging effects for the reactor protection system component type not addressed by the GALL Report consistent with industry experience for this combination of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant adequately concluded that there are no AERMs for the material and environment associated with the components in the reactor protection system.

Aging Management Programs. Because there are no AERMs, no AMPs are required for the reactor protection system.

3.2.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging for the ESF systems components that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concludes that they adequately describe the AMPs credited for managing aging of the ESF systems, as required by 10 CFR 54.21(d).

3.3 Aging Management of Auxiliary Systems

This section of the SER documents the staff's review of the AMR results for the auxiliary systems components and component groups associated with the following systems:

- reactor water cleanup system
- reactor core isolation cooling system
- reactor building sampling system
- post accident sampling system
- circulating water system*
- screen wash water system

- service water system
- reactor building closed cooling water system
- turbine building closed cooling water system*
- diesel generator system
- heat tracing system
- instrument air system
- service air system*
- pneumatic nitrogen system
- fire protection system
- fuel oil system
- radioactive floor drains system
- radioactive equipment drains system
- makeup water treatment system
- chlorination system*
- potable water system
- process radiation monitoring system
- area radiation monitoring system*
- liquid waste processing system
- spent fuel system*
- fuel pool cooling and cleanup system
- HVAC diesel generator building
- HVAC reactor building
- HVAC service water intake structure*
- HVAC turbine building*
- HVAC radwaste building*
- torus drain system
- civil structure auxiliary systems
- non-contaminated water drainage system (NCWDS)

The systems denoted by (*) identifies systems that do not contain mechanical components/commodities requiring AMR. LRA Section 2.3.3 discussed the intended functions and in-scope components/commodities for these systems; the aging management reviews of these systems are discussed elsewhere by the staff in this SER. The AMRs for the remaining systems, those that have mechanical components/commodities requiring AMR, are discussed by the staff in this section.

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant provided AMR results for components. In LRA Table 3.3.1, "Summary of Aging Management Evaluations in Chapter VII or NUREG-1801 for Auxiliary Systems," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the auxiliary systems components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for auxiliary systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.3.2.1.

During the audit, the staff reviewed the AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.3.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.3.2.2.

During the audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating (1) whether all plausible aging effects were identified, and (2) whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.3.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.3.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the auxiliary systems components.

Table 3.3-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.3, that are addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary Systems Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in spent fuel pool cooling and cleanup (Item Number 3.3.1-01)	Loss of material due to general, pitting, and crevice corrosion	Water chemistry and one-time inspection	Water Chemistry Program (B.2.2), One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Linings in spent fuel pool cooling and cleanup system; seals and collars in ventilation systems (Item Number 3.3.1-02)	Hardening, cracking and loss of strength due to elastomer degradation; loss of material due to wear	Plant specific	Systems Monitoring Program (B.2.29), Preventive Maintenance Program (B.2.30)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2)
Components in load handling, chemical and volume control system (PWR), and reactor water cleanup and shutdown cooling systems (older BWR) (Item Number 3.3.1-03)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Table 3.3.2-1	Section 3.3.2.1 and Section 3.3.2.3.1
Heat exchangers in reactor water cleanup system (BWR); high pressure pumps in chemical and volume control system (PWR) (Item Number 3.3.1-04)	Crack initiation and growth due to SCC or cracking	Plant specific		Not applicable (See Section 3.3.2.2)
Components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components (Item Number 3.3.1-05)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Plant specific	One-Time Inspection Program (B.2.15), Systems Monitoring Program (B.2.29), Preventive Maintenance Program (B.2.30)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2)
Components in reactor coolant pump oil collect system of fire protection (Item Number 3.3.1-06)	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-time inspection		Not applicable (See Section 3.3.2.2)
Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system (Item Number 3.3.1-07)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel oil chemistry and one-time inspection	Fuel Oil Chemistry Program (B.2.13), One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, pump casing, and valve body and bonnets in shutdown cooling system (older BWR) (Item Number 3.3.1-08)	Water chemistry and one-time inspection	Water chemistry and one-time inspection		Not applicable (See Section 3.3.2.1)
Heat exchangers in chemical and volume control system (Item Number 3.3.1-09)	Crack initiation and growth due to SCC and cyclic loading	Water chemistry and a plant-specific verification program		Not applicable, PWR only
Neutron absorbing sheets in spent fuel storage racks (Item Number 3.3.1-10)	Reduction of neutron absorbing capacity and loss of material due to general corrosion (Boral, boron steel)	Plant specific		Not applicable (See Section 3.3.2.2)
New fuel rack assembly (Item Number 3.3.1-11)	Loss of material due to general, pitting, and crevice corrosion	Structures monitoring		Not applicable (See Section 3.3.2.2)
Spent fuel storage racks and valves in spent fuel pool cooling and cleanup (Item Number 3.3.1-12)	Crack initiation and growth due to stress corrosion cracking	Water chemistry		Not applicable (See Section 3.3.2.2)
Neutron absorbing sheets in spent fuel storage racks (Item Number 3.3.1-13)	Reduction of neutron absorbing capacity due to Boraflex degradation	Boraflex monitoring		Not applicable (See Section 3.3.2.2)
Closure bolting and external surfaces of carbon steel and low-alloy steel components (Item Number 3.3.1-14)	Loss of material due to boric acid corrosion	Boric acid corrosion		Not applicable, PWR Only
Components in or serviced by closed-cycle cooling water system (Item Number 3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Closed-cycle cooling water system	Closed-Cycle Cooling Water System Program (B.2.8)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Cranes including bridge and trolleys and rail system in load handling system (Item Number 3.3.1-16)	Loss of material due to general corrosion and wear	Overhead heavy load and light load handling systems	Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.9)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.2)
Components in or serviced by open-cycle cooling water systems (Item Number 3.3.1-17)	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-cycle cooling water system	Open-Cycle Cooling Water System Program (B.2.7), Closed-Cycle Cooling Water System Program (B.2.8), Selective Leaching of Materials Program (B.2.16)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.2)
Buried piping and fittings (Item Number 3.3.1-18)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried piping and tanks surveillance or Buried piping and tanks inspection	Buried Piping and Tanks Inspection Program (B.2.17)	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2)
Components in compressed air system (Item Number 3.3.1-19)	Loss of material due to general and pitting corrosion	Compressed air monitoring	One-Time Inspection Program (B.2.15)	Not consistent with GALL (See Section 3.3.2.2)
Components (doors and barrier penetration seals) and concrete structures in fire protection (Item Number 3.3.1-20)	Loss of material due to wear; hardening and shrinkage due to weathering	Fire protection	Fire Protection Program (B.2.10)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components in water-based fire protection (Item Number 3.3.1-21)	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling	Fire water system	Fire Water System Program (B.2.11)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.2)
Components in diesel fire system (Item Number 3.3.1-22)	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire protection and fuel oil chemistry	Fire Protection Program (B.2.10), Fuel Oil Chemistry Program (B.2.13)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Tanks in diesel fuel oil system (Item Number 3.3.1-23)	Loss of material due to general, pitting, and crevice corrosion	Aboveground carbon steel tanks	Aboveground Carbon Steel Tanks Program (B.2.12), Systems Monitoring Program (B.2.29)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.2)
Closure bolting (Item Number 3.3.1-24)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and SCC	Bolting integrity		Not applicable (See Section 3.3.2.2)
Components in contact with sodium pentaborate solution in standby liquid control system (BWR) (Item Number 3.3.1-25)	Crack initiation and growth due to SCC	Water chemistry		Not applicable (See Section 3.3.2.2)
Components in reactor water cleanup system (Item Number 3.3.1-26)	Crack initiation and growth due to SCC and IGSCC	Reactor water cleanup system inspection	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program (B.2.1); Water Chemistry Program (B.2.2)	Not consistent with GALL (See Section 3.3.2.1 and Section 3.3.2.3.1)
Components in shutdown cooling system (older BWR) (Item Number 3.3.1-27)	Crack initiation and growth due to SCC	BWR stress corrosion cracking and water chemistry		Not applicable
Components in shutdown cooling system (older BWR) (Item Number 3.3.1-28)	Loss of material due to pitting and crevice corrosion, and MIC	Closed-cycle cooling water system		Not applicable (See Section 3.3.2.2)
Components (aluminum bronze, brass, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink (Item Number 3.3.1-29)	Loss of material due to selective leaching	Selective leaching of materials	Selective Leaching of Materials Program (B.2.16)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Fire barriers, walls, ceilings, and floors in fire protection (Item Number 3.3.1-30)	Concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel	Fire protection and structures monitoring	Fire Protection Program (B.2.10), Structures Monitoring Program (B.2.23)	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

The staff's review of the BSEP component groups followed one of three approaches depending on the group's consistency with the GALL Report. SER Section 3.3.2.1 discusses the staff's review and documentation of the AMR results for components in the auxiliary systems that the applicant indicated are consistent with the GALL Report and do not require further evaluation; SER Section 3.3.2.2 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended; and SER Section 3.3.2.3 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of BSEP AMPs that are credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.3.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the auxiliary systems components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- BWR Stress Corrosion Cracking Program
- Flow-accelerated Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Program
- Protective Coating Monitoring and Maintenance Program
- Selective Leaching of Materials Program
- Closed-Cycle Cooling Water System Program
- Buried Piping and Tanks Inspection Program
- Open-Cycle Cooling Water System Program
- Preventive Maintenance Program
- Fuel Oil Chemistry Program
- Aboveground Carbon Steel Tanks Program
- Fire Protection Program
- Fire Water System Program

Staff Evaluation. In LRA Tables 3.3.2-1 through 3.3.2-26, the applicant provided a summary of AMRs for the auxiliary systems components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the BSEP AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the BSEP AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

In LRA Section 3.3, the applicant provided the results of its AMRs for the auxiliary systems.

LRA Tables 3.3.2-1 through 3.3.2-25 provide a summary of the applicant's AMR results for components/commodities in the (1) reactor water cleanup (RWCU) system; (2) RCIC system; (3) reactor building sampling system; (4) high post-accident sampling system; (5) screen wash water system; (6) service water system; (7) RBCCW system; (8) DG system; (9) heat tracing system; (10) instrument air system; (11) PMS; (12) fire protection system; (13) fuel oil system; (14) radioactive floor drains system; (15) radioactive equipment drains system; (16) makeup water treatment system; (17) potable water system; (18) PRM system; (19) liquid waste processing system; (20) fuel pool cooling and cleanup system; (21) HVAC diesel generator building; (22) HVAC reactor building; (23) torus drain system; (24) civil structure auxiliary systems; and (25) NCWDS.

Also, for each component type in LRA Table 3.3.1, the applicant identified those components that are consistent with the GALL Report for which no further evaluation is required, those that are consistent with the GALL Report for which further evaluation is recommended, and those that are not addressed in the GALL Report together with the basis for their exclusion.

For AMRs that the applicant stated are consistent with the GALL Report, the staff conducted its audit to determine if the applicant's references to the GALL Report in the LRA are acceptable.

The staff reviewed its assigned LRA line-items to determine that the applicant (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the reactor water cleanup system, reactor core isolation cooling system, reactor building sampling system, post-accident sampling system, screen wash water system, service water system, reactor building closed cooling water system, diesel generator system, heat tracing system, instrument air system, pneumatic nitrogen system, fire protection system, fuel oil system, radioactive floor drains system, radioactive equipment drains system, makeup water treatment system, potable water system, process radiation monitoring system, liquid waste processing system, fuel pool cooling and cleanup system, HVAC diesel generator building, HVAC reactor building, torus drain system, civil structure auxiliary systems, and non-contaminated water drainage system components that are subject to an AMR.

3.3.2.1.1 Loss of Material for Circulating Water Pump Strainers in the Service Water System

In the discussion section of LRA Table 3.3.2-6, the applicant included an AMR line item for strainers in the service water system that are constructed of copper alloy and exposed to raw water on their internal surface. The Open-Cycle Cooling Water System Program is credited for managing loss of material due to crevice corrosion, pitting corrosion, and MIC. GALL Report item

VII.C1.6-a is referenced, which evaluates strainers constructed of carbon steel and stainless steel. This GALL Report line item does not identify copper alloy as one of the materials evaluated. However, generic Note C is noted in the applicant's AMR, indicating consistency with the GALL Report, except for the component. In the audit, the staff asked the applicant why generic Note C was referenced for this AMR.

As documented in the Audit and Review Report, the applicant provided the following explanation for this discrepancy:

> The strainers in question are circulating water pump cooling water strainers in scope for spatial interaction. The assignment of note C was a result of comparing these housings to GALL line item VII.C1.1-a (piping and fittings), which does include copper alloys in a raw water environment. As such, the appropriate GALL reference should be to VII.C1.1-a; not VII.C1.6-a. The service water basket strainers addressed elsewhere in Table 3.3.2-6, are referenced to GALL VII.C1.6-a, and correctly assigned Note A.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.3.2.1.2 Loss of Material for Piping in the Instrument Air System

In the discussion section of LRA Table 3.3.2-10, the applicant included an AMR line item for piping in the instrument air system that is constructed of carbon steel and exposed to indoor air on its internal surface. The One-Time Inspection Program is credited for managing loss of material due to general corrosion for this component; however, GALL Report line item VII.D.1-a recommends the Compressed Air Monitoring Program to manage this aging effect. The applicant's AMR indicates generic Note E, indicating consistency with the GALL Report except for the AMP.

In comparing the AMP recommended in the GALL Report to the applicant's One-Time Inspection Program, the staff noted that the AMP recommended in the GALL Report includes activities in addition to visual inspection for managing this aging effect, such as frequent leak testing of valves, piping, and other system components, and a preventive maintenance program to check air quality at several locations in the system. The applicant's program does not include these activities.

During the audit, the staff asked the applicant to provide justification for concluding that the One-Time Inspection Program is sufficient to manage aging for the piping identified in this AMR line item. In its response, the applicant provided the following explanation:

> In the BSEP LRA Table 3.3.2-10 for the instrument air system, the table line item for piping with indoor air (internal) and the one-time inspection AMP represents components that are in the instrument air system but are not in an instrument air or compressed air environment. The internal environment is indoor air. The components representing the line item are non safety-related piping downstream of relief valves connected to the safety-related nitrogen header and are shown on drawing D-73068-LR Sh 1. The GALL XI.M32 one-time inspection AMP is appropriate for the subject instrument air system piping components.

> As stated in the draft 2005 GALL Report, a one-time inspection may be used to provide additional assurance that aging that has not yet manifested itself is not occurring, that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted. A one-time inspection may also trigger development of a program necessary to assure component intended functions through the period of extended operation. XI.M32 also states that there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that either verify that unacceptable degradation is not occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.
>
> In summary, the subject in-scope instrument air system components are not in an instrument air or a compressed air environment. Thus, a compressed air monitoring program would not be a good fit. Instead, the One-Time Inspection Program was chosen. The use of the one-time inspection AMP is appropriate for the subject instrument air piping components.

The applicant also provided a copy of a BSEP calculation, as documented in the Audit and Review Report, which was reviewed by the staff to confirm the application of the piping in question and the environment identified in the LRA for this component.

The staff determined that, since the subject components are not in a compressed air environment, the compressed air program would not be appropriate for aging management. The One-Time Inspection Program will provide inspections that either verify that unacceptable degradation is not occurring or trigger additional actions that will assure that the intended function of affected components will be maintained during the period of extended operation. Therefore, the One-Time Inspection Program is an acceptable AMP to manage aging for these components.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.3.2.1.3 Loss of Material for Piping and Valves in the Heat Tracing System

In the discussion section of LRA Table 3.3.2-9, the applicant included AMR line items for piping and valves in the heat tracing system that are constructed of carbon steel and exposed to treated water on their internal surface. The One-Time Inspection Program is specified for managing loss of material due to corrosion for these components. Since the environment is treated water, the staff expected that the Water Chemistry Program would also be credited. During the audit, the staff asked the applicant to provide justification for not crediting the Water Chemistry Program, in addition to the One-Time Inspection Program, for aging management. In its response the applicant stated:

> The steam supplied to the heat tracing system from the auxiliary boiler can be classified as treated water. However, it is not appropriate to credit the water chemistry program to prevent aging of the heat tracing system piping. Auxiliary boiler water quality is not controlled to the same water chemistry requirements applicable to reactor feed water. The heat tracing system is used on a very

infrequent basis. The One-Time Inspection Program is considered to be the appropriate program to confirm the extent, if any, of age-related degradation.

The staff reviewed and determined the applicant's response to be acceptable, on the basis that credit cannot be taken for the Water Chemistry Program and a one-time inspection of this infrequently used system will determine the extent of degradation, if any, and any follow-up actions required, prior to entering the extended period of operation. On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2 AMR Results For Which Further Evaluation is Recommended By the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.3.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the auxiliary systems. The applicant provided information concerning how it will manage the following aging effects:

- loss of material due to general, pitting, and crevice corrosion
- hardening and cracking or loss of strength due to elastomer degradation or loss of material due to wear
- cumulative fatigue damage
- crack initiation and growth due to cracking or stress corrosion cracking
- loss of material due to general, microbiologically influenced, pitting, and crevice corrosion
- loss of material due to general, galvanic, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and biofouling
- quality assurance for aging management of NSR components
- crack initiation and growth due to stress corrosion cracking and cyclic loading
- reduction of neutron absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.3.2.2. Details of the staff's audit are documented in the staff's Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

3.3.2.2.1 Loss of Material Due to General, Pitting, and Crevice Corrosion

Spent Fuel Pool Cooling Heat Exchangers. The staff reviewed LRA Section 3.3.2.2.1.1 against the criteria found in SRP-LR Section 3.3.2.2.1:

> Loss of material due to general, pitting, and crevice corrosion could occur in the channel head and access cover, tubes, and tubesheets of the heat exchanger in the spent fuel pool cooling and cleanup [system]. The water chemistry program relies on monitoring and control of reactor water chemistry based on EPRI guidelines of BWRVIP-29 (TR-103515) for water chemistry in BWRs to manage the effects of loss of material from general, pitting or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause general, pitting, or crevice corrosion. Therefore, verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from general, pitting, and crevice corrosion to verify the effectiveness of the water chemistry program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.3.2.2.1.1, the applicant stated that the Water Chemistry Program is used to manage aging effects/mechanisms that could occur on various heat exchanger components in the fuel pool cooling system that are exposed to treated water used as coolant for the fuel pools. The One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program for the management of corrosion for the surfaces of components normally exposed to the fuel pool treated water.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.1 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Spent Fuel Pool Cooling Piping, Valves, Filters, and Ion Exchangers. The staff reviewed LRA Section 3.3.2.2.1.2 against the criteria found in SRP-LR Section 3.3.2.2.1:

> Loss of material due to pitting and crevice corrosion could occur in the piping, filter housing, valve bodies, and shell and nozzles of the ion exchanger in the spent fuel pool cooling and cleanup system. The water chemistry program relies on monitoring and control of reactor water chemistry based on EPRI guidelines of BWRVIP-29 (TR-103515) for water chemistry in BWRs to manage the effects of loss of material from pitting or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause pitting or crevice corrosion. Therefore, verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The

> GALL Report recommends further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of the water chemistry program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.3.2.2.1.2, the applicant stated that the Water Chemistry Program is used to manage aging effects/mechanisms that could occur on various components in the fuel pool cooling system that are exposed to treated water used as coolant for the fuel pools. The One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program for the management of corrosion for the surfaces of components normally exposed to the fuel pool treated water.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.1 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.2 Hardening and Cracking or Loss of Strength Due to Elastomer Degradation or Loss of Material Due to Wear

The staff reviewed LRA Section 3.3.2.2.2 against the criteria found in SRP-LR Section 3.3.2.2.2:

> Hardening and cracking due to elastomer degradation could occur in elastomer linings of the filter, valve, and ion exchangers in spent fuel pool cooling and cleanup systems. Hardening and loss of strength due to elastomer degradation could occur in the collars and seals of the duct and in the elastomer seals of the filters in the control room area, auxiliary and radwaste area, and primary containment heating ventilation systems and in the collars and seals of the duct in the diesel generator building ventilation system. Loss of material due to wear could occur in the collars and seals of the duct in the ventilation systems. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

In LRA Section 3.3.2.2.2, the applicant stated that the plant-specific Systems Monitoring Program is used to manage aging effects/mechanisms for the external surfaces of elastomer components. The Preventive Maintenance Program is used to manage aging effects/mechanisms for the internal surfaces of elastomer components for the emergency diesel generator building, reactor building, and control building ventilation systems. No valve elastomers requiring aging management have been identified in the fuel pool cooling system.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.2 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.3 Cumulative Fatigue Damage

Cumulative fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in LRA Section 4.3.

3.3.2.2.4 Crack Initiation and Growth Due to Cracking or Stress Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.4 against the criteria found in SRP-LR Section 3.3.2.2.4:

> Crack initiation and growth due to SCC could occur in the regenerative and non-regenerative heat exchanger components in the reactor water cleanup system of BWR plants. The GALL Report recommends further evaluation to ensure that these aging effects are managed adequately.

In LRA Section 3.3.2.2.4, the applicant stated that, for the regenerative and non-regenerative heat exchangers in the reactor water cleanup system, this component group is not applicable because only the carbon steel shells of the reactor water cleanup system heat exchangers have an intended function, and carbon steel is typically not subject to SCC.

The staff confirmed that only the carbon steel shells of the regenerative heat exchangers have an intended function and are within the scope of license renewal because they are the anchor in the pipe stress analyses associated with the SR/NSR boundary at valves 1-G31-F042 and 2-G31-F042. The carbon steel shells of the non-regenerative heat exchangers have no intended function, and are not within the scope of license renewal.

The staff agreed with the applicant's assessment that SCC does not apply to the carbon steel shell. Therefore, the staff concluded that the applicant's evaluation is acceptable, on the basis that SRP-LR Section 3.3.2.2.4 is not applicable to BSEP.

3.3.2.2.5 Loss of Material Due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

The staff reviewed the LRA Section 3.3.2.2.5 against the criteria found in SRP-LR Section 3.3.2.2.5:

> Loss of material due to general, pitting, and crevice corrosion could occur in the piping and filter housing and supports in the control room area, the auxiliary and radwaste area, the primary containment heating and ventilation systems; in the piping of the diesel generator building ventilation system, in the above ground piping, and fittings, valves, and pumps in the diesel fuel oil system and in the diesel engine starting air, combustion air intake, and combustion air exhaust subsystems in the EDG system. Loss of material due to general, pitting, crevice and microbiologically influenced corrosion could occur in the duct fittings, access doors, and closure bolts, equipment frames and housing of the duct, due to pitting and crevice corrosion could occur in the heating/cooling coils of the air handler heating/cooling, and due to general corrosion could occur on the external surfaces of all carbon steel SCs, including bolting exposed to operating temperatures less than 212EF in the ventilation systems. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

In LRA Section 3.3.2.2.5, the applicant stated that loss of material on the exterior surfaces of carbon steel components exposed to moist air will be managed using the Systems Monitoring Program for those components with operating temperatures less than 212EF. The One-Time Inspection Program will confirm that aging is managed on the interior surfaces of those components that are exposed to moist air, but not subject to periodic inspection under the Preventive Maintenance Program.

The applicant stated that the components described in LRA Section 3.3.2.2.5 as requiring aging management for loss of material are all constructed of carbon steel, with the exception of a drain valve in the control building HVAC system. The potential for loss of material due to crevice corrosion and pitting corrosion exists for the internal surface of this stainless steel valve located in the condensate drain piping of the control building HVAC system. The internal surface of this valve is normally in a moist air environment and is subject to periodic wetting. The condition of the valve will be confirmed by the One-Time Inspection Program.

LRA Section 3.3.2.2.5 also states that the external surfaces of the plate coils within the penetration cooling system are normally concealed from view, such that routine visual inspection is not practical. These components will be managed with the Preventive Maintenance Program.

LRA Section 3.3.2.2.5 further states that aging of both the exterior and interior surfaces of miscellaneous mechanical components associated with the control building, diesel generator building, service water intake structure, and reactor buildings will be managed for loss of material using the Preventive Maintenance Program. These include sump pump components and back flow valves. The staff noted that the description of the Preventive Maintenance Program in LRA Section B.2.30 includes a table that identifies the components included in the program, and the reactor building is not listed in the line item associated with aging of sump pump components. During the audit, the staff asked the applicant to explain this apparent discrepancy.

As documented in the Audit and Review Report, the applicant provided the following explanation for this discrepancy:

> The table in the description of BSEP AMP B.2.30 is correct. The reactor building sump pumps are associated with the radioactive floor drains system and are subject to a one-time inspection. The further evaluation in Section 3.3.2.2.5 of the BSEP LRA should state ‘...aging of both the exterior and interior surfaces of miscellaneous mechanical components associated with the control building, diesel generator building, and service water intake structure will be managed for loss of material using the preventive maintenance program (BSEP AMP B.2.30)’.

The staff determined the applicant’s response acceptable on the basis that it clarifies the applicant’s AMR for aging management of the reactor building sump pump components. The reactor building sump pumps are included in the radioactive floor drains system and the One-Time Inspection Program will be used to manage aging, which is acceptable.

LRA Section 3.3.2.2.5 further states that aging of exterior surfaces of aboveground carbon steel tanks associated with the fire protection system will be managed by the Aboveground Carbon Steel Tanks Program.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.5 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.6 Loss of Material Due to General, Galvanic, Pitting, and Crevice Corrosion

The staff reviewed the LRA Section 3.3.2.2.6 against the criteria found in SRP-LR Section 3.3.2.2.6:

> Loss of material due to general, galvanic, pitting, and crevice corrosion could occur in tanks, piping, valve bodies, and tubing in the reactor coolant pump oil collection system in fire protection. The fire protection program relies on a combination of visual and volumetric examinations in accordance with the guidelines of 10 CFR Part 50 Appendix R and Branch Technical Position 9.5-1 to manage loss of material from corrosion. However, corrosion may occur at locations where water from wash downs may accumulate. Therefore, verification of the effectiveness of the program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general, galvanic, pitting, and crevice corrosion to verify the effectiveness of the program. A one-time inspection of the bottom half of the interior surface of the tank of the reactor coolant pump oil collection system is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.3.2.2.6, the applicant stated, and the staff agreed, that components in the reactor coolant pump oil collection fire protection system are not applicable since BSEP is not designed with a reactor coolant pump oil collection system. The reactor coolant pumps are contained within the primary containment, which is inerted with nitrogen during normal operation.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.6 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.7 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion, and Biofouling

The staff reviewed LRA Section 3.3.2.2.7 against the criteria found in SRP-LR Section 3.3.2.2.7:

> Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling could occur on the internal surface of tanks in the diesel fuel oil system and due to general, pitting, and crevice corrosion and MIC in the tanks of the diesel fuel oil system in the EDG system. The existing AMP relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination in accordance with the guidelines of ASTM Standards D4057, D1796, D2709 and D2276 to manage loss of material due to corrosion or biofouling. Corrosion or biofouling may occur at locations where contaminants accumulate. Verification of the effectiveness of the

> chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion/biofouling to verify the effectiveness of the program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.3.2.2.7, the applicant stated that the Fuel Oil Chemistry Program manages loss of material and fouling for all components wetted by fuel oil. This also includes the tank and other components supplying fuel to the diesel fire pump. The effectiveness of the Fuel Oil Chemistry Program is confirmed by inspection of fuel oil tanks using the One-Time Inspection Program.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.7 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.8 Quality Assurance for Aging Management of Non-Safety Related Components

The staff addressed this subject in SER Section 3.0.4.

3.3.2.2.9 Crack Initiation and Growth Due to Stress Corrosion Cracking and Cyclic Loading (LRA Section 3.3.2.2.8)

Applicable to PWR systems only.

3.3.2.2.10 Reduction of Neutron Absorbing Capacity and Loss of Material Due to General Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria found in SRP-LR Section 3.3.2.2.10:

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

In LRA Section 3.3.2.2.10, the applicant stated that the boral plates are sandwiched between the inner and outer wall of the rack tubes and are not subject to dislocation, deterioration, or removal. Plant-specific operating experience and testing results of boral sample stations have validated the absence of aging effects. Therefore, no AMP is required for this commodity.

The staff reviewed the applicant’s further evaluation and requested documentation of the test results that support the applicant’s conclusion that no AMP is required. The applicant provided information, as documented in the Audit and Review Report, which included a summary of test results performed in 1989 and 1995. The boral plates were installed in 1984 as part of a spent fuel pool expansion, and boral coupons were tested in 1989 and 1995 to monitor degradation of the boral. The results of the tests showed little change (i.e., no significant aging) of the coupons from their original condition in 1984. Based on these results, the applicant noted that further testing was not warranted. The staff's review of the test results supports this conclusion.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

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

> Loss of material due to general, pitting, and crevice corrosion and MIC could occur in the underground piping and fittings in the open-cycle cooling water system (SW system) and in the diesel fuel oil system. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

In LRA Section 3.3.2.2.11, the applicant stated that the Buried Piping and Tanks Inspection Program will be used for managing loss of material for buried components of the service water and diesel fuel oil systems. The program relies on industry practice and operating experience to manage the effects of loss of material from exterior corrosion.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.11 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommends further evaluation, the staff determined that the applicant adequately addressed the issues that were further evaluated. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3 Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.3.2-1 through 3.3.2-25, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-25, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the

GALL Report and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line-item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line-item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line-item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line-item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

The RAIs are organized in two groups: general RAIs and system-specific RAIs.

General RAIs on AMR Issues:

By letter dated April 25, 2005, the staff requested the applicant to provide additional information on issues described in the following general RAIs (RAIs 3.3-1 through 3.3-4) which are applicable to more than one system. By letter dated May 11, 2005, the applicant responded to these RAIs. In addition, the applicant addressed the use of the One-Time Inspection Program in supplemental response to the staff's RAI 3.3.2-5-1, by letter dated August 11, 2005. The following describes these RAIs, the applicant's responses, and the staff's evaluation of these responses.

Erosion of Plastic/Polymer, Materials In RAI 3.3-1, the staff stated that in LRA Table 3.3.2-5 for the screen wash water system and in Table 3.3.2-6 for the service water system, cracking is identified as an aging effect for plastics/polymer piping exposed to a raw water (internal) environment. Table 3.3.2-5 credits the One-Time Inspection Program and Table 3.3.2-6 credits the Open-Cycle Cooling Water System Program to manage cracking caused by exposure to raw water. LRA Table 3.0-1 describes raw water as water that enters the plant from a river, lake, pond, ocean, or bay that has not been demineralized and has been rough filtered to remove large particles. Small particles in raw water may cause erosion in materials susceptible to erosion. For example, LRA Table 3.3.2-6 identifies copper-alloy materials exposed to raw water as being susceptible to loss of material due to erosion and the open-cycle cooling water system program is credited with managing this aging effect. Therefore, the staff requested that the applicant clarify why loss of material from erosion is not identified for plastics/polymer piping in a raw water environment and to evaluate if a periodic inspection rather than a one-time inspection would be more appropriate to manage aging effects in plastics/polymer piping for the screen wash water system. The applicant was also requested to consider industry and plant operating experience in determining appropriate aging effects and programs to manage this material.

In its response, dated May 11, 2005, the applicant provided the following information:

> The components represented by this line item are elastomeric (i.e., butyl rubber) expansion joints. This material is extremely resistant to erosion and is commonly used in fluid applications where abrasive components are present. Operating experience, to date,

has not identified degradation of these components due to erosion or abrasion. BSEP has conservatively predicted cracking may occur as a result of aging. This aging effect, driven by age related hardening of the rubber expansion joint element, would be a slowly occurring phenomenon for which a one time inspection would be appropriate.

The staff reviewed the applicant’s response and found the response to be reasonable and acceptable because the applicant identified the specific elastomeric material as butyl rubber and clarified that this material is resistant to erosion. The applicant also indicated that operating experience has not identified degradation of these components as a result of erosion or abrasion, and the One-Time Inspection Program is appropriate for a slowly occurring aging effect. Based on the erosion-resistant properties of butyl rubber and operating experience, the staff agreed that erosion is not an applicable aging effect and the One-Time Inspection Program is appropriate to manage other aging effects in plastic/polymer materials. Therefore, the staff’s concern described in RAI 3.3-1 is resolved.

Bolting Integrity In RAI 3.3-2, the staff stated that the auxiliary systems 3.3.2 AMR tables in the LRA do not include bolting, and the Bolting Integrity Program is not credited in the 3.3.2 AMR tables. In LRA Table 3.3.1, Item 3.3.1-24 indicates that the Bolting Integrity Program is not applicable to Non-Class 1 closure bolting, and bolting materials are not itemized as a separate component. This table further states that the Systems Monitoring Program, credited for visual identification of external general corrosion, will also address bolting materials. Therefore, the staff requested that the applicant explain (1) why crack initiation and growth due to cyclic loading and loss of preload are not identified as aging effects for auxiliary systems bolting; (2) the conditions under which certain sizes of cracks can be identified visually in the closure bolting for auxiliary system components; and (3) why the bolting integrity AMP, currently designated for Class 1 closure bolting only, is not credited for managing cracking, loss of preload, and other aging effects for closure bolting in auxiliary system components.

In its response, dated May 11, 2005, the applicant provided the following information:

(1) BSEP has revised its position on bolting in response to NRC concerns raised during the Aging Management Program (AMP) portion of the GALL Consistency Audit. The revised Bolting Integrity Program addresses bolting integrity for each of the NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," system groupings (i.e., Reactor Vessel and Internals and Reactor Coolant System/Class 1, Engineered Safety Features, Auxiliary, and Steam and Power Conversion Systems). Aging management reviews for each these groupings treat bolting as potentially susceptible to loss of material, cracking and loss of preload consistent with NUREG-1800. BSEP uses the Bolting Integrity Program, ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program, and Systems Monitoring for aging management

(2) Physical inspections (i.e., surface and volumetric exams) of Auxiliary System bolting for cracking are performed, to the extent applicable, under the ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program, as noted in the NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," description of the Bolting Integrity Program, XI.M18. Inspection methods and acceptance criteria for these inspections are specified by the ASME Code. BSEP Auxiliary Systems do not utilize high strength pressure boundary bolting, and direct

visual examinations for cracking is not considered necessary. The Bolting Integrity Program does contain elements of materials control, consumables control, and installation/torquing that are preventive in nature and are generally applied to pressure boundary bolting, as well as physical inspections for leakage under the ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program and the Systems Monitoring Program, as applicable.

(3) See the response to item (1), above.

The staff reviewed the applicant's response and found that the response is reasonable and acceptable because the applicant provided sufficient information on how bolting is managed in auxiliary systems. The staff found that revising the Bolting Integrity Program to be consistent with the GALL Report should provide reasonable assurance that bolting in auxiliary systems will be adequately managed to ensure that bolting performs its intended function. Therefore, the staff's concern described in RAI 3.3-2 is resolved.

<u>Aging Effects for Lubricating Oil Environment</u> In RAI 3.3-3, the staff stated that in LRA Tables 3.3.2-6 and 3.3.2-8, no aging effects are identified for certain carbon steel and copper-alloy components in a lubricating oil (LO) environment and no AMPs are credited. Carbon steel and copper-alloy materials may experience loss of material in an oil environment if exposed to contaminants and/or moisture. For example, LRA Table 3.3.2-8 identified certain carbon steel materials in a fuel oil environment that are susceptible to loss of material. GALL Report item VII G.7.2 identifies loss of material for carbon steel and copper-alloy materials in a LO environment with contaminants and/or moisture, and identifies a verification program. In LRA Table 3.0-1, the description of a lubricating oil environment includes the statement that water contamination of lubricating oil is not assumed unless indicated by operating experience or design review. Therefore, the staff requested that the applicant clarify if leakage of raw water or the absence of a chemistry control AMP for the lubricating oil may result in contamination of the LO environment such that aging effects could occur. If such aging effects could occur, the staff also requested that the applicant identify an appropriate AMP to manage the aging effects. Furthermore, the staff also requested that the applicant address industry and plant-specific operating experience for this aging effect.

By letter dated May 11, 2005, the applicant provided the following information:

> The components in question are the "Heat Exchanger (Service Water Pump Motor Cooler Coils)," Lube Oil side, in Table 3.3.2-6, and components of the DG Engines and Lube Oil Systems, in Table 3.3.2-8.
>
> GALL item VII.G7.2 identifies loss of material for copper alloy materials in a lubricating oil (LO) environment for Reactor Coolant Pump Oil Collection System components. Contamination is expected and water intrusion is possible in this system. The environment described in GALL item VII.G7 is not applicable to the SW and DG components in question.
>
> Metals are not corroded by the hydrocarbon components of lubricants. LO is not a good electrolyte, and the oil film on the lubricated surfaces of components tends to minimize the potential for corrosion. Moisture contamination and the use of additives can, however, cause corrosion. Copper and copper alloys, for example, may be attacked by oxidized oil

and active sulfur compounds, especially in the presence of water. One of the functions of almost all lubricants is the prevention of corrosion in the lubricating system by water. The purity of the LO for major BSEP components is maintained and sampled regularly.

Fuel oil can present a much more corrosive environment if there should be an intrusion of water during transportation and storage. Microbiologically-induced corrosion (MIC) is also a potential concern in fuel oil systems. Water and other contaminants, such as chlorides and sulfides, occur naturally in crude oil. While fuel oil in its purest refined form contains little if any moisture, water contamination can occur during storage and transportation. This water contamination, naturally occurring contaminants, and any fuel additives, can produce an environment which is corrosive. Several forms of fungus and other microorganisms can survive and multiply in hydrocarbon fuels. These organisms can occur in all areas of the fuel handling system and need only trace amounts of minerals and water to sustain their growth.

As noted in LRA Table 3.0-1, the BSEP LO environment is defined as oil used in diesel engines, pumps, air compressors, the main turbine, and various LO storage tanks. Water contamination of LO is not assumed unless indicated by operating experience or design review. Loss of material for carbon steel and copper alloys in a LO environment is not observed without contaminants and/or moisture.

Industry Lube Oil Operating Experience

A majority of the significant generic operating experience (OE) correspondence was concerned with either water intrusion or lack of adequate oil and fuel oil purity control. Water intrusion into oil or fuel oil systems can result in a corrosive environment. NRC Information Notice (IN) 79-23, "Emergency Diesel Generator Lube Oil Coolers," and NRC Circular 80-11, "Emergency Diesel Generator Lube Oil Cooler Failures," dealt with specific failures of LO coolers.

NRC Circular #80-11: Emergency Diesel Generator Lube Oil Cooler Failures

Diesel generator LO cooler failures were reported. The DGs were manufactured by Electro-Motive Division (EMD) of General Motors. The failures were caused by severe corrosion of the solder, which sealed the tubes to the tube sheets. These failures occurred in the water side of the coolers. The corrosion inhibitor in use was Calgon CS, a borated-nitrite type inhibitor. The manufacturer of this type of inhibitor has recommended the use of hard solder in CS treated systems. EMD does not recommend the use of Calgon CS since the puddle solder used in EMD radiators and oil coolers is a soft solder of lead-tin composition.

IN 79-23: Emergency Diesel Generator Lube Oil Coolers

Water intrusion in the LO system resulted in trips of both diesel generator units during their surveillance tests. The water intrusion was caused by tube sheet failure in the LO coolers. The failures were cracks around the outer periphery of the tube sheets. Coolers were replaced; however, the failure mechanism was not determined.

Both of these failures were a result of degradation on the treated water side of the LO coolers and provide no evidence of an aging effect requiring management for metals in contact with LO.

BSEP Lube Oil Operating Experience

The LO in major BSEP components is subject to periodic sampling and corrective action. DG engine LO is sampled monthly for water and quarterly for a spectrum of contaminants. Service water pump LO is sampled during routine lubrication. This sampling provides no evidence of water contamination in these components under normal operation.

A review of non-conformance reports over the past 10 years found only one case of water contamination of LO in major components:

A non-conformance report documented the identification of water in the oil of the Unit 2 Reactor Core Isolation Cooling System. The most probable cause was determined to be addition of oil mixed with water when the oil was added during maintenance. Significant water leakage was not considered likely because subsequent oil checks did not show an increase in level. Testing of the LO cooler confirmed that there was no leakage from the tube (i.e., water) side to the shell (i.e., oil) side.

This is considered to be an isolated event that was identified, corrected and is not representative of normal operation for the components in question.

In summary, LO systems generally do not suffer appreciable degradation by cracking or loss of material since the environment is not conducive to corrosion mechanisms. There are some conditions, however, in which moisture intrusion into the systems can result in an aggressive environment. Aging effects requiring management for carbon steel and copper alloy materials in LO are not anticipated unless water contamination is present. A review of maintenance practices and operating experience indicts that the normal LO environment for the BSEP "Heat Exchanger (Service Water Pump Motor Cooler Coils)" and the DG Engine and LO Systems is free of water and harmful contaminants. LO sampling is performed by maintenance on a periodic basis such that leakage of water would be identified and corrected prior to component age related degradation.

The staff reviewed the applicant’s response and found that, although it cites LO sampling, the response did not include a formal lubricating oil analysis AMP or a verification method to demonstrate that the LO analysis program is effective. The staff requested that the applicant submit its oil analysis program or equivalent and a verification program, such as a one-time inspection, to provide objective evidence that verifies that aging effects caused by moisture intrusion are not occurring in systems containing lubricating oil.

By letter dated August 11, 2005, the applicant provided additional information to address this unresolved item. To evaluate potential corrosion in carbon steel and copper-alloy components from water contamination in the lubricating oil, the applicant identified that the Preventive Maintenance Program will incorporate routine sampling and analysis of the lubricating oil in the service water pump reservoir and emergency diesel generator system. The applicant also identified that the One-Time Inspection Program will be used to verify the effectiveness of the LO sampling by visually inspecting a sample of the cooling coils in the service water pump and diesel generator lubricating oil sumps for evidence of corrosion products or moisture.

The applicant’s response is reasonable and acceptable because the applicant will apply the Preventive Maintenance Program to sample/analyze lubricating oil for evidence of corrosion products or moisture and apply the One-Time Inspection Program to verify that the Preventive Maintenance Program is effective in detecting potential aging effects in the lubricating oil system. The application of these two AMPs provides reasonable assurance that aging effects will be detected and corrected before loss of component function. Therefore, all concerns related to RAI 3.3-3 are resolved.

<u>Aging Effects for Various Materials Exposed to Dry Air/Gas (Internal) Environment</u> In RAI 3.3-4, the staff stated that the applicant did not identify aging effects for various materials exposed to a dry air/gas (internal) environment for various component commodities listed in the following LRA tables:

> Table 3.3.2-10, Instrument Air System
> Table 3.3.2-11, Pneumatic Nitrogen System
> Table 3.3.2-12, Fire Protection System
> Table 3.3.2-14, Radioactive Floor Drains System
> Table 3.3.2-15, Radioactive Equipment Drains System
> Table 3.3.2-19, Liquid Waste Processing System
> Table 3.3.2-21, HVAC Diesel Generator Building
> Table 3.3.2-22, HVAC Reactor Building

In the dry air/gas system, components that are located upstream of air dryers are generally exposed to a wet air/gas environment; therefore, they may be subject to loss of material due to general and pitting corrosion. Although it is reasonable to assume that components downstream of the dryers are exposed to a dry air/gas environment, NRC IN 87-28, "Air Systems Problems at U.S. Light Water Reactors," identified that the air/gas system downstream of the dryer may also not be dry. Therefore, the staff requested that the applicant provide the technical basis for not identifying loss of material as an aging effect for these components, including a discussion of the plant-specific operating experience related to components that are exposed to an air environment to support its conclusion.

In its response, by letter May 11, 2005, the applicant provided the following information:

> Dry air/gas (internal) environments identified in the above-referenced LRA tables can be dry gases and/or dry instrument air. The discussions below are for these dry gas and dry instrument air environments.
>
>> Dry Gases - Examples of a dry gas environment include nitrogen, carbon dioxide and Halon-containing components in the Pneumatic Nitrogen System and the Fire Protection System. Experience has shown that commercial grade gases are provided as a high quality product with little if any external contaminants. Based upon nitrogen, carbon dioxide, and Halon environments not being subject to wetting, the BSEP methodology predicted no aging effects for these dry gases.

Dry Instrument Air - The following discussion of the BSEP Instrument Air (IA) System and the Service Air (SA) System provides background for the assignment of no aging effects to in-scope component internal surfaces exposed to dry instrument air. BSEP dry instrument air is neither saturated nor moist. It is noted that all in-scope components served by dry instrument air are located downstream of the IA System and SA System air dryers. There are no in-scope components located upstream of the air dryers. The IA System air compressors, air dryer and SA System air dryers are not in the scope of License Renewal.

Instrument Air System Design

By design, the IA System provides a medium which is dry, oil-free, and free of foreign materials to pneumatically operated instruments and controls throughout the plant. The SA System air dryers dry both SA and IA, while the IA dryer dries only IA. The IA dryer is normally bypassed when the SA dryers are in service. The IA dryer is placed in service if the SA dryers are removed from service or have degraded.

IA and SA are filtered and dried by means of electrically heat reactivated desiccant type dryers, efficient at removing moisture. The inlet of a SA dryer has a coalescing filter capable of removing 90% of the entrained liquid moisture. The SA and IA dryers are described as follows:

Unit 1 SA Dryer: The Unit 1 SA dryer is a heat reactivated vertical dual tower desiccant type designed to supply air dried to a dewpoint of -40°F. This dryer has a bank of electric heaters (i.e., in individual heater tubes) embedded within the desiccant.

Unit 2 SA Dryer: The Unit 2 SA dryer is a heat regenerative vertical dual tower desiccant type designed to supply air dried to a dewpoint of -40°F. The electrically heated dryer is external to the desiccant.

IA dryer: The IA dryer is a dual tower desiccant type dryer with a fully automatic regeneration cycle. This dryer is capable of supplying air dried to a dew point of -40°F.

BSEP is currently in the process of upgrading the air dryers for the Unit 1 and 2 SA Systems.

BSEP Response to Generic Letter 88-14

NRC Generic Letter (GL) 88-14, "Instrument Air Supply System Problems," was issued after several years of study of problems, including those in NRC IN 87-28, and failures of IA systems. GL 88-14 recommended extensive design and operations review and verification of IA systems. Progress Energy has met the intent of GL 88-14. The NRC review of the BSEP response to GL 88-14 stated:

> “The staff has reviewed your response and finds that you have addressed all points stated in the GL.”

NUREG-1801 states:

> "…as a result of Generic Letter 88-14, performance of air systems has improved significantly."

Operating Experience (OE) Review

The aging management review methodology applied at BSEP included use of OE to confirm the set of aging effects that had been identified through material/environment evaluations. Plant-specific and industry OE was identified and reviewed.

BSEP site-specific OE reviews included a review of PassPort EDB and Maintenance Rule databases and Nuclear Assessment Section records. The BSEP Periodic System Review for the IA System examined system aspects such as equipment performance, material indicators, trending results, outstanding modifications, plant workarounds, performance problems and corrosion concerns. The review noted that air sampling for dewpoint had been satisfactory.

The BSEP Air Operated Valves (AOV) Program Health Report was reviewed for health status of green, yellow or red. The results show the program to be in green condition. There were no transients or power reductions caused by AOVs that should have been prevented by the program. There were no systems/components placed in a(1) Maintenance Rule status due to an AOV failure. No corrective actions were recommended. The plant-specific OE review identified no additional unpredicted or unique aging effects requiring management.

Industry OE reviews included those in NUREG-1801. An evaluation of industry OE published since the effective date of NUREG-1801 was also performed to identify any additional aging effects requiring management using the Progress Energy internal OE review process. OE sources subject to review under this process include Institute of Nuclear Power Operations and World Association of Nuclear Operators items, NRC documents (i.e., INs, GLs, Notices of Violation, and staff reports), 10 CFR 21 reports, and vendor bulletins, as well as corporate internal OE information from Progress Energy nuclear sites. The industry OE review identified no additional unpredicted aging effects requiring management.

The IA and SA System Engineer was interviewed. During every refueling outage, the IA System Engineer performs a walkdown of the drywell to inspect for component material condition. No additional information related to aging effects/mechanisms which might affect the components of the IA System within the scope of License Renewal were identified by the System Engineer. A review of operating experience did not identify a pattern of degradation due to moisture for in-scope IA components.

Dry IA Summary

By design, IA is filtered and dried by means of electrically heat reactivated desiccant type dryers, efficient at removing moisture. There are no in-scope components located upstream of the air dryers. To verify dry IA, BSEP currently uses procedures to periodically test air quality, review trend data and initiate corrective actions as appropriate for the IA System and has met the intent of GL 88-14.

A review of operating experience at BSEP did not identify a pattern of degradation due to moisture for in-scope components exposed to the IA environment. Based on the delivery of dry air by the IA System, no aging effects/mechanisms due to IA moisture were identified for IA System in-scope components. Dry air is provided by system design, and is maintained by system operation and testing requirements. The above discussion provides the technical basis for not identifying loss of material as an aging effect for components exposed to an IA environment.

The staff reviewed the applicant's response to RAI 3.3-4 and found that the response is reasonable and acceptable because the applicant clarified that (1) all in-scope components served by dry instrument air are located downstream of the IA system and SA system air dryers; (2) experience has shown that commercial grade gases are provided as a high quality product with little, if any, external contaminants; and (3) an operating experience review has demonstrated that IA system components within scope of license renewal are not subject to degradation due to moisture. The applicant has also addressed all GL 88-14 concerns; moreover, it is currently upgrading the air dryers for the Units 1 and 2 SA systems. Therefore, the staff's concern described in RAI 3.3-4 is resolved.

<u>The Use of One-Time Inspection Program</u>. In a supplemental request for additional information on an issue similar to the one described in RAI 3.3.2-5-1, the applicant was requested to explain why a one-time inspection, rather than periodic inspections, are proposed to manage various components exposed to raw water environment in the radioactive floor drains system (LRA Table 3.3.2-14), the makeup water treatment system (LRA Table 3.3.2-16), and the non-contaminated water drain system (LRA Table 3.3.2-25). In its supplemental response to RAI 3.3.2-5-1, dated August 11, 2005, the applicant stated:

The BSEP LRA identified the potential for aging effects in the Radioactive Floor Drains System (LRA Table 3.3.2-14) and Non-Contaminated Water Drainage System (LRA Table 3.3.2-25), and specified the One-Time Inspection Program for aging management. BSEP has revised the aging management strategy for these components based on the potential for locally aggressive environments, particularly associated with floor drains periodically exposed to Service Water, and roof drains exposed to coastal atmospheric conditions. The revised strategy will utilize the Preventive Maintenance Program to perform inspections of susceptible components on a recurring basis. This revision is intended to provide a greater level of scrutiny to ensure detection of aging effects prior to loss of intended function.

BSEP has also reviewed the aging management strategy for Makeup Water Treatment System (LRA Table 3.3.2-16) and Potable Water (LRA Table 3.3.2-17) components to affirm the adequacy of the One-Time Inspection Program for aging management as specified by the LRA. This review determined that components in these systems are exposed to a relatively benign environment, and that aging effects are expected to progress slowly and predictably. Based on this factor, and supported by the lack of adverse plant operating experience, the One-Time Inspection Program is considered to be appropriate for aging management of these components.

The staff reviewed the applicant's response and found it acceptable because the applicant revised the aging management strategy for components in the radioactive floor drains system and NCWDS to ensure detection of aging effects prior to loss of intended function.

System-Specific Evaluations:

3.3.2.3.1 Reactor Water Cleanup System

The staff reviewed the AMR of the RWCU system component-material-environment-AERM combinations that are assigned to the staff for review. Only those system components beyond the second containment isolation valve are evaluated here. Portions of the system that are part of the RCPB are addressed in LRA Section 3.3.2.1.1 as part of the reactor coolant system. These combinations use Notes F through J in LRA Table 3.3.2-1 identifying them as either not consistent with or not addressed in the GALL Report. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs and TLAAs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-1 lists individual system components within the scope of license renewal and subject to aging management review. The component types with materials not identified in the GALL Report (Note F) include carbon steel piping/fittings and regenerative heat exchanger shell. The component types with an environment not identified in the GALL Report (Note G) include stainless steel piping and fittings in an indoor air environment. The component types with aging effects not identified in the GALL Report (Note H) include stainless steel piping and fittings in a treated water/steam environment. The component types with material and environment combination not evaluated in the GALL Report (Note J) include piping, fittings, valves, tanks, pumps, and piping specialties.

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Stainless steel exposed to indoor air experiences no aging effects.
- Stainless steel in a treated water/steam environment experiences loss of material due to crevice corrosion and pitting corrosion as well as cracking due to SCC and thermal fatigue.
- Carbon steel exposed to treated water/steam experiences loss of material due to crevice corrosion, general corrosion and pitting corrosion as well as cracking due to thermal fatigue. Glass in an indoor air or treated water environment experiences no aging effects.

The staff reviewed the information in LRA Section 2.3.3.1, Table 2.3.3-1, Section 3.3.2.1.1, and Table 3.3.2-1. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's responses, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

In RAI 3.3.2-1-1, dated April 25, 2005, the staff stated that in LRA Table 3.3.2-1, RWCU piping and fitting (small bore piping less than NPS 4) are identified but the location or class of the piping is not identified. Therefore, the staff requested that the applicant clarify whether this small bore piping includes the small bore piping beyond the second isolation valve that is addressed in GALL Report Section VII E3 or is this piping limited to Class 1 piping within the RCPB that is addressed in GALL Report Section IV under the RCS. In its response, by letter dated May 11, 2005, the applicant clarified that components in this line item are inside ASME Class 1 boundaries, as denoted by the reference to GALL IV.C1.1 in column seven. The staff reviewed the applicant's response and found the response to be reasonable and acceptable, because the applicant clarified that this is Class 1 piping within the RCPB that is reviewed separately as part of the RCS system. Therefore, the staff's concern described in RAI 3.3.2-1-1 is resolved.

In RAI 3.3.2-1-3, dated April 25,2005, the staff stated that In LRA Table 3.3.2-1, a treated water environment with steam is identified for various carbon steel components in the RWCU system beyond the second isolation valve. Therefore, the staff requested that the applicant explain why loss of material due to FAC managed by the FAC Program is not identified as an aging effect for carbon steel components beyond the second isolation valve. In its response, by letter dated May 11, 2005, the applicant clarified that its AMR methodology used the environment "treated water (includes steam)" to represent components that may be in a treated water or a steam environment and not a two-phase condition. The staff reviewed the applicant's response and finds the response to be reasonable and acceptable because the applicant clarified that the treated water (includes steam) environment does not represent a two-phase condition; therefore, the FAC Program is not required.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above reactor water cleanup system component types are not addressed by the GALL Report, but are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the RWCU system.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs and TLAAs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR supplement contains an adequate description of the program, in accordance with 10 CFR 54.21(d).

To manage the aging effects described above for the reactor water cleanup system components, LRA Table 3.3.2-1 identifies TLAA(s) evaluated in accordance with 10 CFR 54.21(c) and the following AMPs:

- Water Chemistry Program
- One-Time Inspection Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.1 and 3.0.3.2.11. The staff's evaluation of the TLAAs is addressed in SER Section 4.3.

Based on the above, the staff identified an area in which additional information was necessary to complete the review. The applicant responded to the staff's RAI as discussed below.

In RAI 3.3.2-1-2, dated April 25, 2005, the staff requested that the applicant explain why the BWR RWCU system AMP identified in the GALL Report is not applied and to clarify if the stainless steel piping beyond the second containment isolation valve has been replaced with material not susceptible to IGSCC. In its response, by letter dated May 11, 2005, the applicant clarified that extensive mitigative activities as well as ongoing requirements related to water chemistry and inspections were implemented in response to GL 88-01. For purposes of license renewal, these ongoing requirements are implemented under the Water Chemistry Program and ASME Section XI Subsection IWB, IWC and IWD Program. This response further stated that BSEP considers that the mitigative measures already implemented in response to GL 88-01, in conjunction with these AMPs, are the equivalent of the BWR RWCU AMP. The applicant also clarified that the one-time inspections are generally specified for water chemistry effectiveness verification where volumetric examinations are not otherwise performed. In regard to IGSCC, the applicant stated that BSEP replaced those portions of RWCU piping that were deemed to be susceptible to IGSCC on the basis of NUREG-0313 with non-susceptible materials.

The staff reviewed the applicant's response to RAI 3.3.2-1-2 and found the response to be reasonable and acceptable because the applicant clarified that the mitigative measures already implemented in response to GL 88-01, in conjunction with these aging management programs, are the equivalent of the BWR Reactor Water Cleanup System Aging AMP. In regard to IGSCC, the applicant did not specifically identify whether piping beyond the second isolation valve was replaced; however, the staff determined that, in BSEP letter dated August 20, 1998, the licensee identified that the RWCU system piping outboard of the second containment isolation valve has been replaced with low carbon wrought austenitic stainless steel material in accordance with the recommendations outlined in NUREG-0313, Revision 2. The low carbon stainless steel is resistant to IGSCC. Therefore, the staff also found that the use of a One-Time Inspection Program is appropriate as a chemistry verification program for managing aging effects in stainless steel materials not susceptible to IGSCC that are exposed to treated water. Therefore, the staff's concern described in RAI 3.3.2-1-2 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found that the applicant identified appropriate AMPs and TLAAs for managing aging effects for the reactor water cleanup system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.2 Reactor Core Isolation Cooling (RCIC) System – Table 3.3.2-2

Portions of the piping system contained in the RCIC system (up to the second isolation valve) are Class 1 piping and are within the RCS pressure boundary. The staff's review of this Class 1 piping is provided in SER Section 3.1.2.3.5. The staff's review for the portion of the RCIC piping system and components beyond the second isolation valve is provided in this section.

The staff reviewed LRA Table 3.3.2-2, which summarizes the results of AMR evaluations for the RCIC system component groups.

In LRA Section 3.3.2.1.2, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the RCIC system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Control Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program

The technical staff reviewed the applicant's AMR of the RCIC system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.3.2-2. The staff also reviewed those combinations in Table 3.3.2-2, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

<u>Aging Effects</u>. LRA Table 2.3.3-2 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for AMR include: piping and fittings, pumps, valves, tanks, steam turbines, strainer elements, heat exchangers, and pressure regulators.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (includes steam)(internal), or treated water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion.

- Carbon steel components in treated water (internal) environments are subject to general, crevice, pitting, and galvanic corrosion.

- Carbon steel components in treated water (internal) environments are subject to flow blockage due to fouling.

- Carbon steel components in treated water (includes steam)(internal) environments are subject to loss of material due to FAC.

- Carbon steel components in indoor air (external) environments are subject to loss of material due to general corrosion.

- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion.

- Stainless steel components in treated water (includes steam)(internal), or treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion.

- Stainless steel components in treated water (internal) are subject to flow blockage due to fouling.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to loss of material due to flow-accelerated corrosion.
- Copper alloys in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion, selective leaching, as well as loss of heat transfer effectiveness due to fouling of heat transfer surfaces.
- Grey cast iron components in treated water (internal) environments are subject to loss of material due to selective leaching, as well as loss of material due to crevice, galvanic, general, and pitting corrosion.
- Carbon steel and stainless steel components in indoor air (external) or lube oil (internal) environments are not identified with any AERMs.
- Insulation material in indoor air (external) environments are not identified with any AERMs.
- Copper alloy components in lube oil (external), dry air/gas (internal), or indoor air (external) environments are not identified with any AERMs.
- Glass components in indoor air (external), lube oil (internal), or treated water (internal) environments are not identified with any AERMs.

On the basis of its review of the information provided in the LRA, the staff found that the aging effects of the portion of non-Class 1 RCIC system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the components in the RCIC system.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program, in accordance with 10 CFR 54.21(d).

LRA Table 3.3.2-2 identifies the following AMPs for managing the aging effects described above for the RCIC system:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program
- Water Chemistry Program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Control Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Protective Coating Monitoring and Maintenance Program
- Systems Monitoring Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.1.1, 3.0.3.2.1, 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.11, 3.0.3.2.12, 3.0.3.2.18, and 3.0.3.3.2, respectively.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the RCIC system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.3 Reactor Building Sampling System

The staff reviewed the AMR of the reactor building sampling system component-material-environment-AERM combinations that are assigned to the staff for review. Only those system components beyond the second containment isolation valve are evaluated here. Portions of the system that are part of the RCPB are addressed in LRA section 3.1 as part of the reactor coolant system. These combinations use Note J in LRA Table 3.3.2-3 that are identified as not addressed in the GALL Report. The staff verified that the applicant had identified all applicable AERMs and credited the appropriate AMPs and TLAAs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-3 lists individual system components within the scope of license renewal and subject to AMR. The following component types have material and environment combinations not evaluated in GALL Report (Note J): piping, fittings, valves, heat exchanger shell, flow orifice, pump casing, filters, immersion elements and tank exposed to indoor air or treated water. For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Copper alloy or stainless steel exposed to indoor air experience no aging effects.
- Stainless steel or copper alloy in a treated water environment experiences loss of material due to crevice corrosion and pitting corrosion.
- Stainless steel exposed to treated water also experiences cracking due to SCC and thermal fatigue.

The staff reviewed the information in LRA Section 2.3.3.3, Table 2.3.3-3, Section 3.3.2.1.3, and Table 3.3.2-3. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant’s response, and the staff’s evaluation are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s response to the above RAI, the staff found that the aging effects of the above reactor building sampling system component types that are not addressed by the GALL Report, are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the reactor building sampling system.

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

To manage the aging effects described above for the reactor building sampling system components, LRA Table 3.3.2-3 identifies TLAA(s) evaluated in accordance with 10 CFR 54.21(c) and the following AMPs:

- Water Chemistry Program
- One-Time Inspection Program

The staff's detailed review of these AMPs is found in Sections 3.0.3.2.1 and 3.0.3.2.11 of this SER. The staff's evaluation of the TLAAs is addressed in SER Section 4.3.

ISG-12 and GALL AMP XI.M35 contain special augmented one-time inspection requirements applicable to Class 1 piping less than NPS-4. The sample lines identified by Note I appear to be part of the RCPB normally within the GALL Report Section IV C1 scope of review in SER Section 3.1.2.3.5.

In RAI 3.3.2-3-1, dated April 25, 2005, the staff requested that the applicant clarify which stainless steel piping and its aging management programs are part of the RCPB and which piping and its aging management programs are not part of the RCPB. The staff also requested that the applicant clarify if this piping is less than NPS-4. In its response, by letter dated May 11, 2005, the applicant clarified that the RCPB portions of the reactor building sampling system are the 3/4-inch stainless steel reactor sample lines 1/2-reactor building sampling system (RXS)-1. Therefore, this piping within the RCPB is within scope of the GALL Report RCPB (Section IV) review in SER Section 3.1.2.3.5.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found that the applicant identified the appropriate AMPs and TLAAs for managing the aging effects for the reactor building sampling system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.4 Post Accident Sampling System

The staff reviewed the AMR of the post-accident sampling system component-material-environment-AERM combinations that are assigned to the staff for review. These combinations use Note J in LRA Table 3.3.2-4 and are identified as not addressed in the GALL Report. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-4 lists individual system components within the scope of license renewal and subject to AMR. The following component types have material and environment combinations not evaluated in GALL Report (Note J): piping, fittings, valves and heat exchanger shell.

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Copper alloy or stainless steel exposed to indoor air experience no aging effects.
- Stainless steel or copper alloy in a treated water environment experiences loss of material due to crevice corrosion and pitting corrosion.
- Copper alloy in treated water is also susceptible to selective leaching.

The staff reviewed the information in LRA Section 2.3.3.4, Table 2.3.3-4, Section 3.3.2.1.4 and Table 3.3.2-4. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above post-accident sampling system component types that are not addressed by the GALL Report, are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the post-accident sampling system.

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

LRA Table 3.3.2-4 identifies TLAAs and the following AMPs for managing the aging effects described above for the post-accident sampling system components assigned to the staff for review:

- Water Chemistry Program
- Closed-Cycle Cooling Water System Program
- One-Time Inspection Program
- Selective Leaching of Materials Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.1, 3.0.3.2.5, 3.0.3.2.11 and 3.0.3.2.12.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found that the applicant identified the appropriate AMPs for managing the aging effects for the post-accident sampling system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.5 Screen Wash Water System

The staff reviewed the AMR of the screen wash water system component-material-environment-AERM combinations that are assigned to the staff for review. These combinations use Note J in LRA Table 3.3.2-5 and are identified as not addressed in the GALL Report. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-5 lists individual system components within the scope of license renewal and subject to an AMR. The following component types have material and environment combinations not evaluated in GALL Report (Note J): piping, fittings, valves, pump casing and strainer body exposed to indoor air or raw water.

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Copper alloy or stainless steel exposed to indoor air experience no aging effects.
- Stainless steel in a raw water environment experiences loss of material due to crevice corrosion, MIC and pitting corrosion.
- Plastics/polymers exposed to indoor air or raw water experience cracking due to various aging mechanisms.
- Copper alloys exposed to raw water experience loss of material due to crevice corrosion, pitting corrosion, erosion, selective leaching and MIC.
- Carbon steel in a raw water environment experiences loss of material due to crevice, general, MIC and pitting corrosion.

The staff reviewed the information in LRA Section 2.3.3.6, Table 2.3.3-5, Section 3.3.2.1.5, and Table 3.3.2-5. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-1 and 3.3-2 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above screen wash water system component types that are not addressed by the GALL Report, are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the screen wash water system.

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

LRA Table 3.3.2-5 identifies the following AMPs for managing the aging effects described above for the screen wash water system components assigned to the staff for review:

- One-Time Inspection Program
- Selective Leaching of Materials Program
- Systems Monitoring Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.11, 3.0.3.2.12, and 3.0.3.3.2.

In RAI 3.3.2-5-1, dated April 25, 2005, the staff stated that the One-time inspection is appropriate where either an aging effect is not expected to occur but there is insufficient data to completely rule it out, or the aging effect is expected to occur very slowly so as not to affect the component intended function. Therefore, the staff requested that the applicant explain why one-time inspection rather than periodic inspections are proposed to manage various components exposed to raw water in the screen wash system. In its response, by letter dated May 11, 2005, the applicant clarified that the screen wash water (SCW) system performs no safety function and is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) for potential spacial interaction considerations. The applicant explained that as a result of corrosion experienced in both stainless steel and carbon steel cement lining materials, problematic portions of the SCW system were replaced with copper-nickel, a material that has proven itself to be well suited to raw water at BSEP. The applicant stated that approximately 20 years of operating experience supports that age-related degradation of copper-nickel piping components in the SCW system is sufficiently slow to utilize a one-time inspection for aging management. The applicant further explained that the portions of the system constructed of stainless steel or carbon steel are maintained in accordance with the Maintenance Rule requirements or have not been problematic. The remaining in-scope stainless steel piping is limited to small diameter, low-pressure lines used to periodically flush the self-cleaning strainers. The applicant concluded that operating experience with the current SCW system materials has been favorable and all in-scope components within the SCW system are subject to the One-Time Inspection Program. In the event that age-related degradation is found during inspection activities, the extent of the condition will be evaluated under the Corrective Action Program and appropriate follow-up activities will be planned.

Staff reviewed the applicant's response and found the response to be reasonable and acceptable because the applicant identified sufficient plant-specific operating experience to assure that the aging is sufficiently slow in these materials such that a one-time inspection is appropriate to manage the aging effects. The staff agreed with the applicant that there is reasonable assurance that, in the event that age-related degradation is found during Maintenance Rule or one-time inspection activities, the extent of the condition will be evaluated under the Corrective Action Program and appropriate follow-up activities will ensure that these 10 CFR 54.4(a)(2) components will be capable of performing their intended function. Therefore, the staff's concern described in RAI 3.3.2-5-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found that the applicant. with the appropriate AMPs, will manage the aging effects for the screen wash water system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.6 Service Water System

The staff reviewed the AMR of the service water system component-material-environment-AERM combinations that are assigned to the staff for review. These combinations use Notes F through J in LRA Table 3.3.2-6 and are identified as either not consistent with or not addressed in the GALL Report. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-6 lists individual system components that are within the scope of license renewal and subject to an AMR. The component type with material not identified in the GALL Report is stainless steel pump casing. The following component types have aging effects not identified in the GALL Report (Note H): copper-alloy piping, fittings, and valves and carbon steel basket strainers. The following component types have material and environment combinations not evaluated in GALL Report (Note J): piping, fittings, valves, flow orifice, pump casing and strainer body exposed to indoor air; piping specialties exposed to raw water and heat exchanger coils exposed to LO.

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Copper alloy or stainless steel exposed to indoor air experience no aging effects.
- Stainless steel in a raw water environment experiences flow blockage due to fouling and loss of material due to crevice corrosion, MIC, and pitting corrosion.
- Plastics/polymers exposed to indoor air or raw water experience cracking due to various aging mechanisms.
- Copper alloys exposed to LO experience no aging effects.
- Copper alloys exposed to raw water experience loss of material due to erosion.
- Carbon steel connected to a more noble metal exposed to raw water experiences loss of material due to galvanic corrosion.

The staff reviewed the information in LRA Section 2.3.3.7, Table 2.3.3-6, Section 3.3.2.1.6 and Table 3.3.2-6. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-1, 3.3-2, and 3.3-3 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

In RAI 3.3.2-6-1, dated April 25, 2005, the staff stated that LRA Table 3.3.2-6 identifies no aging effects for copper-alloy underground piping and fittings in an external air environment. Therefore, the staff requested that the applicant clarify whether underground piping is in a tunnel or buried and to explain why this environment is considered an indoor environment with no sustained wetting. In its response, by letter dated May 11, 2005, the applicant responded to RAI 3.3.2-6-1 by clarifying that the copper-nickel lines connect to the underground nuclear service water in a protected enclosure and then run for a short distance underground before emerging into the basement of the DG Building. The applicant stated that BSEP aging management methodology considers that raw water and buried environments generally produce comparable aging effects consisting of crevice corrosion, pitting corrosion, and MIC. The applicant clarified that BSEP will apply the Buried Piping and Tanks Inspection Program to manage this buried piping.

The staff found that the applicant’s response is reasonable and acceptable because the applicant clarified that a portion of the nuclear service water piping is underground with comparable aging effects of a raw water environment and the Buried Piping and Tanks Inspection Program will manage these aging effects on the external surfaces of this piping. Therefore, the staff’s concerns described in RAI 3.3.2-6-1 are resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s responses to the above RAIs, the staff found that the aging effects of the above service water system component types that are not addressed by the GALL Report, are consistent with industry experience for these combinations of materials and environments. Other than the aging effect of loss of material for buried copper-alloy piping, the staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the service water system.

<u>Aging Management Programs</u>. After evaluating the applicant’s identification of aging effects for each of the above components, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.3.2-6 identifies the following AMPs for managing the aging effects described above for the service water system components assigned to the staff for review:

- Open-Cycle Cooling Water System Program
- Systems Monitoring Program

The staff’s detailed review of these AMPs is found in SER Sections 3.0.3.2.4 and 3.0.3.3.2.

LRA Table 3.3.2-6 does not credit the Buried Piping and Tanks Inspection Program for any components in the service water system. In the response to RAI 3.3.2-6-1 the applicant clarified that BSEP will also apply the Buried Piping and Tanks Inspection program to manage buried piping in this system. The staff’s detailed evaluation of this AMP is found in Section 3.0.3.2.17

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s response to the above RAIs, the staff found that the applicant identified the appropriate AMPs for managing the aging effects for the service water system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.7 Reactor Building Closed Cooling Water System

The staff reviewed the AMR of the reactor building closed cooling water system component-material-environment-AERM combinations that are assigned to the staff for review. These combinations use Notes F and J in LRA Table 3.3.2-7 and are identified as not addressed in the GALL Report. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-7 lists individual system components within the scope of license renewal and subject to aging management review. The following component types materials not included in the GALL Report (Note F): stainless steel piping, valves and piping specialties. The following component types have material and environment not evaluated in the GALL Report (Note J): piping, piping specialties, valves, and pressure regulators exposed to indoor air or dry air.

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Copper alloy, stainless steel or glass exposed to indoor air or dry air/gas experience no aging effects.
- Stainless steel in a treated water environment experiences loss of material due to crevice and pitting corrosion.
- Glass in a treated water environment experiences no aging effects.

The staff reviewed the information in LRA Section 2.3.3.8, Table 2.3.3-7, Section 3.3.2.1.7, and Table 3.3.2-7. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above reactor building closed cooling water system component types that are not addressed by the GALL Report, are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the reactor building closed cooling water system.

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

LRA Table 3.3.2-7 identifies the Closed-Cycle Cooling Water System Program (B.2.8) for managing the aging effects described above for the reactor building closed cooling water system components assigned to the staff for review.

The staff's detailed review of this AMP is found in SER Sections 3.0.3.2.5.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the applicant identified the appropriate AMPs for managing the aging effects for the reactor building closed cooling water system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.8 Diesel Generator System

The staff reviewed the AMR of the diesel generator system component-material-environment-AERM combinations that are assigned to the staff for review. These combinations use Notes F through J in LRA Table 3.3.2-8 and are identified as either not consistent with or not addressed in the GALL Report. The staff verified that the applicant identified all the applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-8 lists individual system components within the scope of license renewal and subject to aging management review. The following component types have materials not in the GALL Report (Note F): stainless steel pipe and fittings, and copper-alloy drain traps. The component types with environment not identified in the GALL Report (Note G) for the material are piping, fittings, valves, pump casings and tanks. The following component types have aging effects not identified in the GALL Report (Note H): copper-alloy tubes, tubesheets, pipes and fittings and carbon steel pipe and fittings. The following component types have material and environment combinations not evaluated in GALL Report (Note J): piping, fittings, tubing, valves, immersion element, pump casing, gauge glass, filter shell, strainer, filter media, tanks, heat exchangers, drain trap, inlet and exhaust bellows, muffler, oil separator, fans and piping specialties.

For these component types, the applicant identified the following materials, environments, and AERMs as specified below:

- Copper alloy, stainless steel or glass exposed to indoor air or LO experience no aging effects, except stainless steel bellows are susceptible to loss of material due to crevice and pitting corrosion in an indoor air environment (subject to condensation).
- Carbon steel in an LO environment experiences no aging effects.
- Carbon steel in an outdoor air environment experiences loss of material due to general, crevice and pitting corrosion as well as MIC and general chemical attack for the exhaust muffler.
- Stainless steel, copper alloys, and carbon steel in a fuel oil environment experience loss of material due to MIC.

- Stainless steel in a treated water environment experiences loss of material due to crevice corrosion and pitting corrosion.
- Glass in a treated water environment experiences no aging effects.
- Grey cast iron in a treated water environment experiences loss of material due to crevice corrosion, galvanic corrosion, general corrosion, pitting corrosion and selective leaching.
- Carbon steel in a treated water environment experiences loss of material due to crevice, galvanic, general and pitting corrosion.
- Copper-alloy heat exchanger tubes and tubesheets in a raw water environment experience loss of heat transfer due to fouling and loss of material due to erosion.
- Copper-alloy heat exchanger tubes in a treated water environment experiences loss of heat transfer due to fouling and loss of material due to crevice corrosion, pitting corrosion and selective leaching.

The staff reviewed the information in LRA Section 2.3.3.10, Table 2.3.3-8, Section 3.3.2.1.8, and Table 3.3.2-8. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-2 and 3.3-3 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

In RAI 3.3.2-8-1, dated April 25, 2005, the staff stated that in LRA Table 3.3.2-8, the materials for strainer (basket) and filter (media) are identified as filter media and strainer element, respectively. Therefore, the applicant was requested to identify the specific materials (carbon steel, stainless steel, etc.) for the strainer (basket) and filter (media). In its response, by letter dated May 11, 2005, the applicant identified the following various configurations of strainers/filters in the diesel generator system:

- lube oil system strainers/filters - carbon steel for coarse straining and stainless for fine
- starting air system basket strainers - Monel
- Intake air oil bath filter - stainless steel

In its response, dated May 11, 2005, the applicant identified that a loss of material aging effect is not predicted by BSEP methodology for these material and environment combinations. The applicant also identified that strainer/filter elements are subject to the Preventive Maintenance Program.

The staff reviewed the applicant's response and found the response reasonable and acceptable because the applicant identified the specific materials and environments for filters/strainers. The staff agreed that, unless contaminants are present, loss of material is not predicted for these material and environment combinations. Any potential degradation due to the presence of contaminants would be detected and corrected by the Preventive Maintenance Program.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above diesel generator system component types that are not addressed by the GALL Report, are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the diesel generator system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR supplement contains an adequate description of the program, in accordance with 10 CFR 54.21(d).

LRA Table 3.3.2-8 identifies the following AMPs for managing the aging effects described above for the diesel generator system components assigned to the staff for review:

- Open-Cycle Cooling Water System Program
- Closed-Cycle Cooling Water System Program
- Fuel Oil Chemistry Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Systems Monitoring Program
- Preventive Maintenance Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.4, 3.0.3.2.5, 3.0.3.2.9, 3.0.3.2.11, 3.0.3.2.12, 3.0.3.3.2, and 3.0.3.3.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found that the applicant identified appropriate AMPs for managing the aging effects for the diesel generator system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.9 Heat Tracing System

The staff reviewed the AMR of the heat tracing system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-9. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs and TLAAs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-9 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are piping and fittings (steam drains), and valves (check, control, hand, motor operated, safety valves) (body and bonnet).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

(g) carbon steel components exposed to treated water (includes steam) (internal) experience loss of material due to general corrosion as well as cracking due to thermal fatigue.

The staff reviewed the information in LRA Section 2.3.3.11, Table 2.3.3-9, Section 3.3.2.1.9, and Table 3.3.2-9. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above heat tracing system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the heat tracing system.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.3.2-9 identifies TLAA and the One-Time Inspection Program to manage the aging effects described above for the heat tracing system components that are not addressed by the GALL Report.

The staff's detailed review of this AMP is found in SER Sections 3.0.3.2.11. The staff's evaluation of the TLAAs is addressed in SER Section 4.3.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs and TLAAs for managing the aging effects of the heat tracing system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.10 Instrument Air (IA) System

The staff reviewed the AMR of the instrument air system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-10. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs.

<u>Aging Effects</u>. LRA Table 2.3.3-10 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are piping (piping and fittings), and valves (including check valves and containment isolation valves) (body and bonnet).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel, copper alloys, aluminum alloys or stainless steel components exposed to dry air/gas (internal) experience no aging effects.
- Carbon steel-galvanized components exposed to either indoor air (internal) or indoor air (external) environments have no aging effects.
- Aluminum alloys, carbon steel-galvanized, copper alloys, or stainless steel components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.12, Table 2.3.3-10, Section 3.3.2.1.10, and Table 3.3.2-10. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above instrument air system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the instrument air system.

Aging Management Programs. LRA Table 3.3.2-10 identifies no AMP on the basis that no aging effects are identified for the component types described above for the instrument air system.

On the basis of its review of the information provided in the LRA, the staff agreed with the applicant that no AMP is needed for managing the aging effects of the instrument air system component types that are not addressed by the GALL Report.

3.3.2.3.11 Pneumatic Nitrogen System (PNS)

The staff reviewed the AMR of the pneumatic nitrogen system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-11. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs.

Aging Effects. LRA Table 2.3.3-11 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are piping (piping and fittings), valves (including check valves and containment isolation valves) (body and bonnet), filter (shell and access cover), and non-carbon steel components (external surfaces).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Stainless steel or aluminum-alloy components exposed to dry air/gas (internal) experience no aging effects.
- Aluminum alloys or stainless steel components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.14, Table 2.3.3-11, Section 3.3.2.1.11, and Table 3.3.2-11. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above PNS component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the PNS.

Aging Management Programs. LRA Table 3.3.2-11 identifies no AMP on the basis that no aging effects are identified for the component types described above for the PNS.

On the basis of its review of the information provided in the LRA, the staff agreed with the applicant that no AMP is needed for managing the aging effects of the PNS component types that are not addressed by the GALL Report.

3.3.2.3.12 Fire Protection (FP) System

The GALL Report describes requirements for aging management of the FP system based on the combination of component type, material, and environment.

Aging Effects. LRA Table 3.3.2-12 for the auxiliary systems for the Units 1 and 2 FP system summarizes the AMP for each of the combinations mentioned above. When the combinations do not exactly match the requirements of the GALL Report, the LRA table includes a note indicating that the prescribed AMP has been modified for use or that another AMP is being used.

For the Fire Protection Water System

For the combination of piping and fittings, aluminum alloys, raw water, the Fire Water System Aging Management Program is used to manage aging effects. A table note indicates the material is not in the GALL Report for this component.

For the combination of piping and fittings, carbon steel, raw water, the Fire Water System Aging Management Program is used to manage aging effects. A table note indicates that the combination for component, material, environment, and aging effect is consistent with the GALL Report.

For the combination of piping and fittings, glass, raw water, no aging effect is anticipated and no AMP is in place. A table note indicates the material is not in the GALL Report for this component, and no aging is anticipated.

For the combination of piping and fittings, stainless steel, and raw water, the Fire Water System Aging Management Program is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect.

For the combination of filter, fire hydrants, mulsifier, pump casing, sprinkler, strainer, valve body, carbon steel, and raw water, the Fire Water System Aging Management Program is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect.

For the combination of filter, fire hydrants, mulsifier, pump casing, sprinkler, strainer, valve body, copper alloys, and raw water, the Fire Water System AMP is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect. The Selective Leaching of Materials AMP is used to manage the aging effects of loss of material due to selective leaching. A table note indicates that this aging effect is not in the GALL Report for this component, material, and environment combination.

For the combination of filter, fire hydrants, mulsifier, pump casing, sprinkler, strainer, valve body, grey cast iron, and raw water, the Fire Water System AMP is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect. The Selective Leaching of Materials AMP is used to manage the aging effects of loss of material due to selective leaching. A table note indicates that this aging effect is not in the GALL Report for this component, material, and environment combination.

For the combination of filter, fire hydrants, mulsifier, pump casing, sprinkler, strainer, valve body, stainless steel, and raw water, the Fire Water System AMP is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect.

For the combination of HTX, heat exchanger shell and access cover, carbon steel, and treated water (internal), the Fire Protection AMP is used to manage aging effects. A table note indicates that neither the component nor this aging effect is in the GALL Report for this material and environment combination.

For the combination of HTX, heat exchanger tubes, copper alloys, raw water (internal), the Fire Water System AMP is used to manage aging effects due to loss of material. A table note indicates that for the loss of material aging effect the component is different from, but consistent with the GALL Report for component, material, environment, and aging effect.

For the combination of HTX, heat exchanger tubes, copper alloys, and treated water (external), the Fire Protection AMP is used to manage aging effects due to loss of material. A table note indicates that neither the component nor this aging effect is in the GALL Report for this material and environment combination.

For the combination of HTX, Heat exchanger tubes, copper alloys, and raw water (internal), the Fire Water System AMP is used to manage aging effects due to loss of heat transfer effectiveness due to fouling of heat transfer surfaces. A table note indicates that neither the component nor this aging effect is in the GALL Report for this material and environment combination.

For the combination of HTX, heat exchanger tubes, copper alloys, and treated water (external), the Fire Protection AMP is used to manage aging effects due to loss of heat transfer effectiveness due to fouling of heat transfer surfaces. A table note indicates that neither the component nor this aging effect is in the GALL Report for this material and environment combination.

For the combination of diesel-driven fire pump and fuel supply line, grey cast iron, and raw water (internal), the Fire Water System AMP is used to manage aging effects. A table note indicates the component is different from, but consistent with the GALL Report for material, environment, and aging effect. The Selective Leaching of Materials AMP is used to manage the aging effects of loss of material due to selective leaching. A table note indicates that this aging effect is not in the GALL Report for this component, material, and environment combination.

For the combination of carbon steel components (external surfaces)(includes carbon steel fire water tank), and carbon steel, buried (external), the Buried Piping and Tanks Inspection AMP is used to manage aging effects. A table note indicates the environment is not in the GALL Report for this component.

For the combination of carbon steel components (external surfaces)(includes carbon steel fire water tank), carbon steel, and indoor air (external), the Systems Monitoring AMP is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect, but a different AMP is credited.

For the combination of carbon steel components (external surfaces)(includes carbon steel fire water tank), carbon steel, and outdoor air (external), the Aboveground Carbon Steel Tanks AMP is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect, but a different AMP is credited.

For the combination of carbon steel components (external surfaces)(includes carbon steel fire water tank), carbon steel-galvanized, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of carbon steel components (external surfaces)(includes carbon steel fire water tank), carbon steel-galvanized, and outdoor air (external), the Systems Monitoring AMP is used to manage aging effects. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect

For the combination of carbon steel components (external surfaces)(includes carbon steel fire water tank), and grey cast iron, buried (external), the Selective Leaching of Materials AMP is used to manage the aging effects of loss of material due to selective leaching. A table note indicates that this aging effect is not in the GALL Report for this component, material, and environment combination. The Buried Piping and Tanks Inspection AMP is used to manage aging effects due to loss of material. A table note indicates the environment is not in the GALL Report for this component.

For the combination of non-carbon steel components (external surfaces), aluminum alloys, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of non-carbon steel components (external surfaces), copper alloys, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of non-carbon steel components (external surfaces), glass, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of non-carbon steel components (external surfaces), stainless steel, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the Fire Protection CO_2 System

For the combination of CO_2 fire suppression installed in the HPCI, carbon steel, and dry air/gas (internal), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of CO_2 fire suppression installed in the HPCI, copper alloys, and dry air/gas (internal), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of carbon steel components (external surfaces), carbon steel, and indoor air (external), the Systems Monitoring AMP is credited for managing the aging effect of the loss of material. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect, but a different AMP is credited.

For the combination of carbon steel components (external surfaces), carbon steel-galvanized, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of non-carbon steel components (external surfaces), copper alloys, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the Halon System

For the combination of Halon fire suppression installed in the diesel generator building (DGB), aluminum alloys, and dry air/gas (internal), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of Halon fire suppression installed in the DGB, carbon steel, and dry air/gas (internal), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of Halon fire suppression installed in the DGB, copper alloys, and dry air/gas (internal), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of Halon fire suppression installed in the DGB, stainless steel, and dry air-gas (internal), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of carbon steel components (external surfaces), carbon steel, and indoor air (external), the Systems Monitoring AMP is credited for managing the aging effect of the loss of material. A table note indicates consistent with the GALL Report for component, material, environment, and aging effect, but a different AMP is credited.

For the combination of non-carbon steel components (external surfaces), aluminum alloys, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of non-carbon steel components (external surfaces), copper alloys, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

For the combination of non-carbon steel components (external surfaces), stainless steel, and indoor air (external), no aging effect is anticipated and no AMP is credited. A table note indicates neither the component nor the material and environment combination is evaluated in the GALL Report.

Conclusion

During its review of the information provided in the LRA, license renewal drawings, and licensing-basis information, the staff did not identify any omissions or discrepancies in the applicant’s scoping and screening results for the components of the fire protection systems.

3.3.2.3.13 Fuel Oil System

The staff reviewed the AMR of the fuel oil system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-13. The staff verified that the applicant has identified all applicable AERMs and credited the appropriate AMPs and TLAAs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-13 lists individual system components within the scope of license renewal and subject to aging management review AMP. The component types that do not rely on the GALL Report for an AMR are diesel-driven fire pump and fuel supply line, valves body and tubing, valves body and tubing, diesel fuel tank, piping (aboveground pipe and fittings), valves (body and bonnet), and tank (internal/external surface).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to buried (external) environment experience loss of material due to crevice, general, pitting corrosion, microbiologically induced corrosion (MIC), and aggressive chemical attack.
- Copper-alloy components exposed to fuel oil (internal) are subject to loss of material due to MIC.
- Copper-alloy components exposed to indoor air (external) experience on aging effects.

The staff reviewed the information in LRA Section 2.3.3.16, Table 2.3.3-13, Section 3.3.2.1.13, and Table 3.3.2-13. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above fuel oil system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the fuel oil system.

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

LRA Table 3.3.2-13 identifies the following AMPs for managing the aging effects described above for the fuel oil system components that are not addressed by the GALL Report :

- Buried Piping and Tank Inspection
- Fuel Oil Chemistry
- Fire Protection

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.13, 3.0.3.2.9, and 3.0.3.2.7.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the fuel oil system component types that are not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.3.2.3.14 Radioactive Floor Drains System

The staff reviewed the AMR of the radioactive floor drains system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-14. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effect. LRA Table 2.3.3-14 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are piping (piping and fittings), valves (body and bonnet), flow orifice (body), pump (casing), tank (shell), drain system sump pumps.

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to raw water (internal) are subject to loss of material due to crevice, general, and pitting corrosion, and MIC.
- Grey cast iron exposed to either raw water (external) or raw water (internal) are subject to loss of material due to crevice, general, and pitting corrosion, MIC, and selective leaching.
- Stainless steel components exposed to raw water (internal) are subject to loss of material due to crevice and pitting corrosion, and MIC.
- Copper-alloy components exposed to either dry air/gas (internal) or indoor air (external) experience no aging effects.
- Stainless steel components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.17, Table 2.3.3-14, Section 3.3.2.1.14, and Table 3.3.2-14. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above radioactive floor drain system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the radioactive floor drains system.

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

LRA Table 3.3.2-14 identifies the following AMPs for managing the aging effects described above for the radioactive floor drains system components that are not addressed by the GALL Report:

- One-Time Inspection Program
- Selective Leaching of Materials Program

The staff's detailed review of the Selective Leaching of Materials Program, is found in SER Sections 3.0.3.2.12. In the applicant's supplemental response RAI 3.3.2-5-1, as described at the beginning of SER Section 3.3.2.3, the applicant revised its aging management strategy for managing the aging effects of the components in this system by replacing the One-Time Inspection Program with the Preventive Maintenance Program. The staff's detailed review of the Preventive Maintenance Program is found in SER Section 3.0.3.3.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's supplemental response to the above RAI, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the radioactive floor drains system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.15 Radioactive Equipment Drains System

The staff reviewed the AMR of the radioactive equipment drains system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-15. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-15 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an

AMR are piping (piping and fittings), valves (body and bonnet), heat exchanger (shell and access cover), flow orifice (body), pump (casing), and tank (shell).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion, general corrosion, and pitting corrosion.
- Stainless steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion and pitting corrosion.
- Copper-alloy components exposed to either dry air-gas (internal) or indoor air (external) experience no aging effects.
- Stainless steel components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.18, Table 2.3.3-15, Section 3.3.2.1.15, and Table 3.3.2-15. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above radioactive equipment drains system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the radioactive equipment drains system.

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

LRA Table 3.3.2-15 identifies the following AMPs for managing the aging effects described above for the radioactive equipment drains system components that are not addressed by the GALL Report:

- One-Time Inspection Program
- Water Chemistry Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.11 and 3.0.3.2.1.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the radioactive equipment drains system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.16 Makeup Water Treatment System

The staff reviewed the AMR of the makeup water treatment system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-16. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-16 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are (1) water treatment system: piping (piping and fittings) and valves (body and bonnet); and (2) demineralized water system: piping (piping and fittings), valves (body and bonnet), and tank (shell).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to indoor air (external) are subject to loss of material due to general corrosion.
- Carbon steel components exposed to raw water (internal) environment experience loss of material due to crevice corrosion, general corrosion, MIC, and pitting corrosion.
- Stainless steel components exposed to raw water (internal) environment are subject to loss of material due to crevice corrosion, MIC, and pitting corrosion.
- Stainless steel components exposed to indoor air (external) experience no aging effects.
- Stainless steel components exposed to treated water (internal) environment are subject to loss of material due to crevice corrosion and pitting corrosion.
- Carbon steel components exposed to treated water (internal) environment experience loss of material due to crevice corrosion, general corrosion and pitting corrosion.
- Grey cast steel components exposed to treated water (internal) are subject to loss of material due to selective leaching.
- Grey cast iron or aluminum-alloy components exposed to treated water (internal) environment are subject to loss of material due to crevice corrosion, galvanic corrosion, and pitting corrosion.
- Aluminum-alloy components exposed to outdoor air (external) environment are subject to loss of material due to crevice corrosion and pitting corrosion.

The staff reviewed the information in LRA Section 2.3.3.19, Table 2.3.3-16, Section 3.3.2.1.16, and Table 3.3.2-16. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above makeup water treatment system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the makeup water treatment system.

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

LRA Table 3.3.2-16 identifies the following AMPs for managing the aging effects described above for the makeup water treatment system components that are not addressed by the GALL Report:

- One-Time Inspection Program
- Selective Leaching of Materials Program
- Systems Monitoring Program
- Water Chemistry Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.11, 3.0.3.2.12, 3.0.3.3.2, and 3.0.3.2.1. With regard to the use of the One-Time Inspection Program, the applicant's supplemental response to RAI 3.3.2-5-1, as described at the beginning of SER Section 3.3.2.3 is applicable to this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's supplemental response to the above RAI, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the makeup water treatment system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.17 Potable Water System (PWS)

The staff reviewed the AMR of the potable water system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-17. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs and TLAAs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-17 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are piping (piping and fittings), valves (body and bonnet), and tank (shell).

For this component type, the applicant identified the following materials, environments, and AERMs, as specified below:

- Copper-alloy components exposed to raw water (internal) are subject to loss of material due to MIC. Copper-alloy components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.21, Table 2.3.3-17, Section 3.3.2.1.17, and Table 3.3.2-17. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above potable water system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the potable water system.

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

LRA Table 3.3.2-17 identifies the One-Time Inspection Program (B.2.15) for managing the aging effects described above for the potable water system components that are not addressed by the GALL Report :

The staff's detailed review of this AMP is found in SER Sections 3.0.3.2.11. With regard to the use of the One-Time Inspection Program, the applicant's supplemental response to RAI 3.3.2-5-1, as described at the beginning of SER Section 3.3.2.3 is applicable to this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's supplemental response to the above RAI, the staff found that the applicant identified an appropriate AMP for managing the aging effect of the potable water system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.18 Process Radiation Monitoring (PRM) System

The staff reviewed the AMR of the process radiation monitoring system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-18. The staff verified that the applicant identified all applicable AERMs and credited no AMP for managing the AERMs.

Aging Effect. LRA Table 2.3.3-18 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are Closed-Cycle Cooling Water System Program (Piping Specialties).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to indoor air (external) environment experience no aging effects (This particular line item pertains to instrument wells protected from the external environment, and is not susceptible to external corrosion as explained in plant-specific Note 341 in Table 3.3.2-18).

The staff reviewed the information in LRA Section 2.3.3.22, Table 2.3.3-18, Section 3.3.2.1.18 and Table 3.3.2-18. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above process radiation monitoring system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the process radiation monitoring system.

Aging Management Programs. LRA Table 3.3.2-18 identifies no AMP on the basis that no aging effects are identified for the component types described above for the process radiation monitoring system.

On the basis of its review of the information provided in the LRA, the staff agrees with the applicant that no AMP is needed for managing the aging effects of the process radiation monitoring system component types that are not addressed by the GALL Report.

3.3.2.3.19 Liquid Waste Processing System

The staff reviewed the AMR of the liquid waste processing system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-19. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-19 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an

AMR are piping (piping and fittings), valves (body and bonnet), immersion element (pressure-retaining housing) and tank (shell).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion, general corrosion, and pitting corrosion.
- Stainless steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion and pitting corrosion.
- Carbon steel components exposed to dry air/gas (internal) experience no aging effects.
- Stainless steel components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.24, Table 2.3.3-19, Section 3.3.2.1.19 and Table 3.3.2-19. During its review, the staff determined that additional information was needed to complete its review.

General RAIs 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above liquid waste processing system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the liquid waste processing system.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.3.2-19 identifies the following AMPs for managing the aging effects described above for the liquid waste processing system components that are not addressed by the GALL Report:

- One-Time Inspection Program
- Water Chemistry Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.11 and 3.0.3.2.1.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the liquid waste processing system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.20 Fuel Pool Cooling and Cleanup System

The staff reviewed the AMR of the fuel pool cooling and cleanup system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-20. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-20 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for an AMR are piping (piping, fittings and flanges), valves (check and hand valves)(body and bonnet), heat exchanger (shell and access cover), heat exchanger (channel head and access cover), and pump (casing).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- carbon steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion, general corrosion, and pitting corrosion.
- Glass components exposed to either treated water (internal) or indoor air (external) experience no aging effects.
- Stainless steel components exposed to indoor air (external) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.26, Table 2.3.3-20, Section 3.3.2.1.20, and Table 3.3.2-20. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant’s response, and the staff’s evaluation are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant’s response to the above RAI, the staff found that the aging effects of the above fuel pool cooling and cleanup system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the fuel pool cooling and cleanup system.

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

LRA Table 3.3.2-20 identifies the following AMPs for managing the aging effects described above for the fuel pool cooling and cleanup system components that are not addressed by the GALL Report:

- One-Time Inspection Program
- Water Chemistry Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.11 and 3.0.3.2.1.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the fuel pool cooling and cleanup system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.21 HVAC Diesel Generator Building

The staff reviewed the AMR of the HVAC diesel generator building relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-21. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

<u>Aging Effects</u>. LRA Table 2.3.3-21 lists individual system components within the scope of license renewal and subject to aging management review. The following component types do not rely on the GALL Report for an AMR: piping (piping and fittings), valves (including check valves and containment isolation valves) (body and bonnet), air receiver (shell and access cover), duct (duct fittings, access doors, and closure bolts), duct (equipment frames and housing), carbon steel and non-carbon steel components (external surfaces).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel, copper alloys, or aluminum-alloy components exposed to dry air/gas (internal) experience no aging effects.
- Carbon steel-galvanized components exposed to either indoor air (internal) or indoor air (external) environments have no aging effects.
- Aluminum alloys, carbon steel-galvanized, or copper-alloy components exposed to indoor air (external) experience no aging effects.
- Stainless steel components exposed to outdoor air (internal) are subject to loss of material due to crevice corrosion and pitting corrosion.
- Carbon steel galvanized components exposed to outdoor air (internal) are subject to loss of material due to aggressive chemical attack and general corrosion.
- Carbon steel components exposed to outdoor air (external) are subject to general corrosion.

- Elastomers exposed to indoor air (external) are subject to cracking due to various degradation mechanisms and loss of material due to wear. Plastics/polymers components exposed to either indoor air (internal) or indoor air (external) are subject to cracking due to various degradation mechanisms.
- Certain plastics/polymers components exposed to indoor air (internal) experience no aging effects.

The staff reviewed the information in LRA Section 2.3.3.27, Table 2.3.3-21, Section 3.3.2.1.21, and Table 3.3.2-21. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant's responses, and the staff's evaluations are described at the beginning of SER Section 3.3.2.3.

<u>Aging Effects of Piping and Duct Components Made of Plastics/Polymers Exposed to Indoor Air (Internal)</u>. In RAI 3.3.2.21-1, dated April 25, 2005, the staff stated that in LRA Table 3.3.2-21 for HVAC diesel generator building, the applicant credited the Preventive Maintenance Program for managing the aging effect of cracking due to various degradation mechanisms for piping (piping and fittings) made of plastics/polymers exposed to indoor air (internal). However, in the same table, no aging effect was identified for the same material exposed to the same environment for duct (duct, fittings, fan housing, damper housing, access doors, and closure bolts). Therefore, the staff requested that the applicant explain the difference between these two cases.

In response, by letter dated May 11, 2005, the applicant stated that, while the material in both cases appears to be the same, they are actually different materials in a group of materials called "plastics/polymers."

The components represented by LRA Table 3.3.2-21, "Piping (Piping and Fittings)," made from plastics/polymers are polyethylene tubing, located indoors. For polyethylene in an indoor air environment, the BSEP methodology predicted the aging effect/mechanism of cracking due to various degradation mechanisms.

The applicant further stated that, components represented by LRA Table 3.3.2-21, "Duct, (Duct, Fittings, Fan Housings, Damper Housings, Access Doors, and Closure Bolts)," made from plastics/polymers, are tornado venting rupture disks constructed of Teflon, located indoors. This Teflon is not expected to be subject to extreme environmental conditions of adverse chemicals, severe thermal stress, high radiation field or continuous ultraviolet rays. For Teflon in this indoor air environment, the BSEP methodology predicted no aging effect/mechanism based upon the above and a review of industry guidance. Therefore, the applicant concluded that the subject materials are different, thus the aging effect/mechanism is different, and there is no inconsistency between the two items.

The staff reviewed the applicant's response to RAI 3.3.2-21-1 and found the response to be reasonable and acceptable because the applicant clarified that the subject materials are different; thus the aging effect/mechanism is different. Therefore, the staff's concern described in RAI 3.3.2-21-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above HVAC diesel generator building component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the HVAC diesel generator building.

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

LRA Table 3.3.2-21 identifies the following AMPs for managing the aging effects described above for the HVAC diesel generator building components that are not addressed by the GALL Report:

- Systems Monitoring Program
- Preventive maintenance Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.3.2 and 3.0.3.3.3.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified an appropriate AMP for managing the aging effects of the HVAC diesel generator building component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.22 HVAC Reactor Building

The staff reviewed the AMR of the HVAC reactor building relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-22. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-22 lists individual system components within the scope of license renewal and subject to aging management review. The following component types do not rely on the GALL Report for an AMR: piping (piping and fittings), valves (including check valves and containment isolation valves) (body and bonnet), air receiver (shell and access cover), duct (duct fittings, access doors, damper housing, and closure bolts), duct (flexible collars between ducts and fans), air handler heating/cooling (heating/cooling coils),filters (elastomer seals), carbon steel and non-carbon steel components (external surfaces), and non-carbon steel components (external surfaces) (heat exchanger).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel, copper alloys, or aluminum-alloy components exposed to dry air/gas (internal) experience no aging effects.

- Carbon steel components exposed to either indoor air (internal) or indoor air (external) are subject to loss of material due to general corrosion.
- Either carbon steel-galvanized or stainless steel components exposed to indoor air (internal) environments experience no aging effects.
- Plastics/polymers exposed to either indoor air (internal) or indoor air (external) experience no aging effects.
- Copper alloys exposed to raw water (internal) are subject to (1) loss of material due to erosion, galvanic corrosion, and MIC, and (2) loss of heat transfer effectiveness due to fouling of heat transfer surfaces.
- Elastomers exposed to either indoor air (internal) or indoor air (external) are subject to loss of material due to wear, and cracking due to various degradation mechanisms.
- Carbon steel components exposed to outdoor air (external) are subject to general corrosion. Aluminum alloys, carbon steel-galvanized, copper-alloy or stainless steel components exposed to indoor air (external) experience no aging effects.
- Stainless steel components exposed to outdoor air (internal) are subject to loss of material due to crevice corrosion and pitting corrosion.
- Copper alloys (heat exchanger) (external surfaces) exposed to indoor air (external) are subject to (1) loss of material due to crevice corrosion and pitting corrosion, and (2) loss of heat transfer effectiveness due to fouling of heat transfer surfaces.

The staff reviewed the information in LRA Section 2.3.3.28, Table 2.3.3-22, Section 3.3.2.1.22, and Table 3.3.2-22. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 and 3.3-4 are applicable to this system. These RAIs, the applicant’s responses, and the staff’s evaluations are described at the beginning of SER Section 3.3.2.3.

<u>Aging Effect of Non-Carbon Steel Components Made of Plastics/Polymers Exposed to Indoor Air (External)</u> In RAI 3.3.2-22-1, dated April 25, 2005, the staff stated that in LRA Table 3.3.2-21 for the diesel generator building HVAC, the applicant credited the Systems Monitoring Program for managing the aging effect of cracking due to various degradation mechanisms for non-carbon steel components made of plastics/polymers exposed to indoor air (external). However, in LRA Table 3.3.2-22 for the reactor building HVAC, no aging effect was identified for the same component commodity made of the same material exposed to the same environment. Therefore, the staff requested that the applicant explain the inconsistency between these two items.

In response, by letter dated May 11, 2005, the applicant stated that while the material in both cases appears to be the same, they are actually different materials in a group of materials called “plastics/polymers.”

The components represented by LRA Table 3.3.2-21, HVAC diesel generator building system, component commodity "Non-Carbon Steel Components (External Surfaces)," made from plastics/polymers, are polyethylene tubing located indoors. For polyethylene in an indoor air environment, the BSEP methodology predicted the aging effect/mechanism of cracking due to various degradation mechanisms.

The applicant further stated that components represented by LRA Table 3.3.2-22, HVAC reactor building system, component commodity "Non-Carbon Steel Components (External Surfaces)," made from plastics/polymers, are ductwork viewing panels constructed of polycarbonate and located indoors. This polycarbonate is not expected to be subject to extreme environmental conditions of adverse chemicals, severe thermal stress, high radiation field or continuous ultraviolet rays. For polycarbonate in this indoor air environment, the BSEP methodology predicted no aging effect/mechanism based upon the above and a review of industry guidance.

The applicant noted that the subject materials are different, thus the aging effect/mechanism is different, and there is no inconsistency between the two items.

The staff reviewed the applicant's response to RAI 3.3.2-22-1 and found the response to be reasonable and acceptable because the applicant clarified that the subject materials are different, thus the aging effect/mechanism is different. Therefore, the staffs concern described in RAI 3.3.2-22-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above HVAC reactor building component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the HVAC reactor building.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects. The staff also verified that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.3.2-22 identifies the following AMPs for managing the aging effects described above for the HVAC reactor building components that are not addressed by the GALL Report:

- Systems Monitoring Program
- Preventive maintenance Program
- Open-Cycle Cooling Water System Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.3.2, 3.0.3.3.3, and 3.0.3.2.4.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the HVAC reactor building component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.23 Torus Drain System

The staff reviewed the AMR of the torus drain system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-23. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-23 lists individual system components within the scope of license renewal and subject to an AMR. The following component types do not rely on the GALL Report for an AMR: piping and fittings (miscellaneous auxiliary and drain piping and valves).

For these component types, the applicant identified the following materials, environments, and AERMs, as specified below:

- Carbon steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion, general corrosion, and pitting corrosion.
- Stainless steel components exposed to indoor air (external) experience no aging effects.
- Stainless steel components exposed to treated water (internal) are subject to loss of material due to crevice corrosion and pitting corrosion.

The staff reviewed the information in LRA Section 2.3.3.32, Table 2.3.3-23, Section 3.3.2.1.23, and Table 3.3.2-23. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no relevant system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above torus drain system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the torus drain system.

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

LRA Table 3.3.2-23 identifies the following AMPs for managing the aging effects described above for the torus drain system components that are not addressed by the GALL Report:

- One-Time Inspection Program
- Water Chemistry Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.11 and 3.0.3.2.1.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the torus drain system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.24 Civil Structure Auxiliary System

The staff reviewed the AMR of the civil structure auxiliary system relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-24. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-24 lists individual system components within the scope of license renewal and subject to aging management review. The following component types do not rely on the GALL Report for an AMR: (1) primary containment auxiliary systems: piping (piping and fittings), and valves (body and bonnet); (2) service water intake structure auxiliary systems: piping (piping and fittings), valves (body and bonnet), pump (casing), and gauge glasses (pressure-retaining housing); (3) diesel generator building auxiliary systems: piping (piping and fittings), valves (body and bonnet), and pump (casing); and (4) control building auxiliary systems: piping (piping and fittings), valves (body and bonnet), and pump (casing).

For these component types, the applicant identified the following materials, environments, and AERMs:

(1) In primary containment auxiliary systems:

- Stainless steel components exposed to either indoor air (external) or indoor air (internal) experience no aging effects.

(2) In service water intake structure auxiliary systems:

- Neither plastics/polymers nor glass components exposed to indoor (external) and raw water (internal) experience aging effects; copper-alloy components exposed to indoor air (external) experience no aging effects, but when exposed to raw water (internal) are subject to loss of material due to crevice corrosion, MIC, pitting corrosion and selective leaching.
- Grey cast iron components exposed to either raw water (external) or raw water (internal) are subject to loss of material due to crevice corrosion, general corrosion, MIC, pitting corrosion, and selective leaching.

(3) In diesel generator building auxiliary systems:

- Carbon steel components exposed to raw water (internal) are subject to loss of material due to crevice corrosion, general corrosion, MIC, and pitting corrosion.
- Grey cast iron components exposed to either raw water (external) or raw water (internal) are subject to loss of material due to crevice corrosion, general corrosion, MIC, pitting corrosion, and selective leaching.

(4) In control building auxiliary systems:

- Carbon steel components exposed to raw water (internal) are subject to loss of material due to crevice corrosion, general corrosion, MIC, and pitting corrosion; grey cast iron components exposed to either raw water (external) or raw water (internal) are subject to loss of material due to crevice corrosion, general corrosion, MIC, pitting corrosion, and selective leaching.

The staff reviewed the information in LRA Section 2.3.3.33, Table 2.3.3-24, Section 3.3.2.1.24, and Table 3.3.2-24. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

Aging Effect of Piping (Piping and Fittings) Components Made of Plastics/Polymers Exposed to Indoor Air (External) and Raw Water (Internal) In RAI 3.3.2-24-1, dated April 25, 2005, the staff stated that in LRA Table 3.3.2-24 for civil structure auxiliary system, no aging effects were identified for piping (piping and fittings) made of plastics/polymers exposed to indoor air (external) and raw water (internal); however, different conclusions were reached for the same components of the same material exposed to the same environments as described in Table 3.3.2-5 and Table 3.3.2-6. Therefore, the staff requested that the applicant explain the apparent inconsistencies cited above. The applicant was also requested to clarify why loss of material from erosion is not identified for plastics/polymer piping and fittings exposed to raw water (internal), and what AMP will be used to manage this aging effect (Refer to General RAI 3.3-1, which is addressed at the beginning of SER Section 3.3.2.3).

In response, by letter dated May 11, 2005, the applicant stated that the plastics/polymer piping noted in LRA Table 3.3.2-24 for civil structure auxiliary systems is polyvinylchloride (PVC) piping associated with the service water intake system (SWIS) sump pumps. These pumps only operate periodically and do not create the high flow velocities needed for erosion. BSEP methodology does not predict aging effects requiring management for PVC exposed to indoor air (external) and raw water (internal) environments. In actual practice, this piping will be visible for inspection as part of the preventive maintenance activities associated with the SWIS sump pumps.

The applicant further stated that the butyl rubber expansion joints noted in LRA Table 3.3.2-5 and Table 3.3.2-6 were conservatively evaluated as potentially susceptible to the cracking due to aging as explained in the response to RAI 3.3-1. The SCW system is subject to continuous, high-flow, high-vibration operation in a brackish water environment. The SW coupling to the diesel service water system noted in LRA Table 3.3.2-6 is of the same design, but used infrequently. Aging effects for these expansion joints are expected to be more likely in the SCW system application.

Therefore, the applicant concluded that the material composition and operating conditions are different between the plastics/polymers components noted in LRA Table 3.3.2-24 and LRA Tables 3.3.2-5 and 3.3.2-6, thus warranting different assessments of AERMs.

The staff reviewed the applicant's response to RAI 3.3.2-24-1 and found the response to be reasonable and acceptable because the applicant clarified that the subject materials are different, thus the aging effect/mechanism is different. Therefore, the staff's concern described in RAI 3.3.2-24-1 is resolved.

During the scoping review, in the applicant's response to RAI 2.3.3.29-1, dated June 14, 2005, the applicant added three line items (one for fan housing, one for damper housing, and one for bird screens) to the AMR associated with LRA Table 3.3.2-24. The applicant stated that, in the SWIS auxiliary systems, components such as duct (equipment frames and housing), duct (debris screens), and fans (pressure retaining housing), all made of carbon steel, exposed to either outdoor air (external) or outdoor air (internal) are subject to loss of material due to general corrosion. The Systems Monitoring Program will manage this aging effect. The staff found the applicant's response to be reasonable and acceptable because the identified aging effect will be adequately managed.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff found that the aging effects of the above civil structure auxiliary system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the civil structure auxiliary system.

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

LRA Table 3.3.2-24 identifies the following AMPs for managing the aging effects described above for the civil structure auxiliary system components that are not addressed by the GALL Report:

- Selective Leaching of Materials Program
- Preventive Maintenance Program
- Systems Monitoring Program

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.2.12, 3.0.3.3.3, and 3.0.3.3.2.

On the basis of its review of the information provided in the LRA, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the civil structure auxiliary system component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.2.3.25 Non-contaminated Water Drainage System (NCWDS)

The staff reviewed the AMR of the NCWDS relating to those component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations use Notes F through J in LRA Table 3.3.2-25. The staff verified that the applicant identified all applicable AERMs and credited the appropriate AMPs and TLAAs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. LRA Table 2.3.3-25 lists individual system components within the scope of license renewal and subject to aging management review. The component type that does not rely on the GALL Report for an AMR is piping (piping and fittings).

For this component type, the applicant identified the following material, environment, and AERMs, as specified below:

- Carbon steel components exposed to raw water (internal) are subject to loss of material due to crevice corrosion, general corrosion, MIC, and pitting corrosion.

The staff reviewed the information in LRA Section 2.3.3.34, Table 2.3.3-25, Section 3.3.2.1.25, and Table 3.3.2-25. During its review, the staff determined that additional information was needed to complete its review.

General RAI 3.3-2 is applicable to this system. This RAI, the applicant's response, and the staff's evaluation are described at the beginning of SER Section 3.3.2.3.

There are no system-specific RAIs associated with this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the above NCWDS component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the NCWDS.

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

LRA Table 3.3.2-25 identifies the One-Time Inspection Program for managing the aging effects described above for the non-contaminated water drainage system components that are not addressed by the GALL Report.

As a result of the applicant's supplemental response to RAI 3.3.2-5-1 as described at the beginning of SER Section 3.3.2.3, the applicant revised the aging management strategy in replacing the One-Time Inspection Program by the Preventive Maintenance Program for managing the aging effects of the components in this system. The staff's detailed review of the Preventive Maintenance Program, is found in SER Section 3.0.3.3.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's supplemental response to the above RAI, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the NCWDS component types that are not addressed by the GALL Report. In addition, the staff found the program description in the UFSAR supplement acceptable.

3.3.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging for the of the auxiliary systems components, that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the auxiliary systems, as required by 10 CFR 54.21(d).

3.4 Aging Management of Steam and Power Conversion Systems

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion system components and component groups associated with the following systems:

- main steam system
- extraction steam system
- moisture separator reheater drains system and reheat steam system
- auxiliary boiler
- feedwater system
- heater drains and miscellaneous vents and drains
- condensate system
- turbine building sampling system
- main condenser gas removal system
- turbine electro-hydraulic control system
- turbine lube oil system
- stator cooling system
- hydrogen seal oil system

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant provided AMR results for components. In LRA Table 3.4.1, "Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion Systems," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the steam and power conversion system components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and are summarized in SER Section 3.4.2.1.

During the audit, the staff reviewed the AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.4.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.4.2.2.

During the audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating (1) whether all plausible aging effects were identified, and (2) whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.4.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.4.2.3.

Finally, in accordance with 10 CFR 54.21(d), the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the steam and power conversion system components.

Table 3.4-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.4, that are addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping and fittings in main feedwater line, steam line and AFW piping (PWR only) (Item 3.4.1-01)	Cumulative fatigue damage			Not applicable, PWR only

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head and shell (except main steam system) (Item 3.4.1-02)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Water chemistry and one-time inspection	Water Chemistry Program (B.2.2), One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2)
Auxiliary feedwater (AFW) piping (Item 3.4.1-03)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Plant specific		Not applicable, PWR only
Oil coolers in AFW system (lubricating oil side possibly contaminated with water (Item 3.4.1-04)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC	Plant specific		Not applicable, PWR only
External surface of carbon steel components (Item 3.4.1-05)	Loss of material due to general corrosion	Plant specific	Systems Monitoring Program (B.2.29)	Consistent with GALL, which recommends further evaluation (See Section 3.4.2.2)
Carbon steel piping and valve bodies (Item 3.4.1-06)	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	Flow-Accelerated Corrosion Program (B.2.5)	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.2)
Carbon steel piping and valve bodies in main steam system (Item 3.4.1-07)	Loss of material due to pitting and crevice corrosion	Water chemistry	Water Chemistry Program (B.2.2), One-Time Inspection Program (B.2.15)	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.2)
Closure bolting in high-pressure or high-temperature systems (Item 3.4.1-08)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity		Not applicable (See Section 3.4.2.2)
Heat exchangers and coolers/condensers serviced by open-cycle cooling water (Item 3.4.1-09)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-cycle cooling water system		Not applicable (See Section 3.4.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Heat exchangers and coolers/condensers serviced by closed-cycle cooling water (Item 3.4.1-10)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-cycle cooling water system		Not applicable (See Section 3.4.2.2)
External surface of aboveground condensate storage tank (Item 3.4.1-11)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Aboveground carbon steel tanks	Aboveground Carbon Steel Tanks Program (B.2.12)	Consistent with GALL, which recommends no further evaluation (See Section 3.4.2.2)
External surface of buried condensate storage tank and AFW piping (Item 3.4.1-12)	Loss of material due to general, pitting, and crevice corrosion and MIC	Buried piping and tanks surveillance or Buried piping and tanks inspection		Not applicable (See Section 3.4.2.2) Not applicable (See Section 3.4.2.2)
External surface of carbon steel components (Item 3.4.1-13)	Loss of material due to boric acid corrosion	Boric acid corrosion		Not applicable, PWR only

The staff's review of the BSEP component groups followed one of three approaches depending on the group's consistency with the GALL Report. Section 3.4.2.1 discusses the staff's review and documentation of the AMR results for components in the steam and power conversion system that the applicant indicated are consistent with the GALL Report and do not require further evaluation; SER Section 3.4.2.2 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended; and SER Section 3.4.2.3 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are Consistent with the GALL Report

<u>Summary of Technical Information in the Application</u>. In LRA Section 3.4.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the steam and power conversion system components:

- Flow-Accelerated Corrosion Program
- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Aboveground Carbon Steel Tanks Program
- Buried Piping and Tanks Inspection Program

- Selective Leaching of Materials Program

Staff Evaluation. In LRA Tables 3.4.2-1 through 3.4.2-7, the applicant provided a summary of AMRs for the steam and power conversion system components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

In LRA Section 3.4, the applicant provided the results of its AMRs for the steam and power conversion systems.

In LRA Tables 3.4.2-1 through 3.4.2-7, the applicant provided a summary of the applicant's AMRs results for components/commodities in the following systems: (1) main steam; (2) auxiliary boiler; (3) feedwater; (4) heater drains and miscellaneous vents and drains; (5) condensate; (6) turbine building sampling; and (7) main condenser gas removal.

The summary information for each component type included intended function; material; environment; aging effect requiring management; AMPs; the GALL Report Volume 2 item; cross reference to the LRA Table 3.4.1 (Table 1); and generic and plant-specific notes related to consistency with the GALL Report.

Also, the applicant identified for each component type in the LRA Table 3.4.1 those components that are consistent with the GALL Report for which no further evaluation is required, those that are consistent with the GALL Report for which further evaluation is recommended, and those that are not addressed in the GALL Report together with the basis for their exclusion.

For AMRs that the applicant stated are consistent with the GALL Report and for which no further evaluation is recommended, the staff conducted its audit to determine whether the applicant's references to the GALL Report in the LRA are acceptable.

The staff reviewed its assigned LRA line-items to determine that the applicant: (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the main steam, auxiliary boiler, feedwater, heater drains and miscellaneous vents and drains, condensate, turbine building sampling, and main condenser gas removal system components that are subject to an AMR.

3.4.2.1.1 Loss of Material for Closure Bolting in High Temperature and Pressure Systems

In the discussion section of LRA Table 3.4.1, item number 3.4.1-08, the applicant addressed aging management of closure bolting in the steam and power conversion system. The applicant stated that the Bolting Integrity Program is not applicable since this system does not use high-strength pressure boundary bolting. For non-Class 1 closure bolting, the applicant considers bolting to be a subcomponent of the associated component; therefore, bolting materials are not itemized as a separate component and the Bolting Integrity Program is not needed for aging management.

During the audit, the staff reviewed LRA Tables 3.4.2-1 through 3.4.2-7 and noted that the AMR line items for the steam and power conversion systems specify the Systems Monitoring Program for visual inspection of the external surfaces of components, including any bolting associated with the component, to identify general corrosion. However, this AMP does not address the crack initiation and growth aging effect for pressure-retaining bolting. the GALL Report recommends the GALL AMP XI.M18 (Bolting Integrity Program) to manage loss of material due to general corrosion, and crack initiation and growth due to cyclic loading and/or SCC for all closure bolting in high-pressure or high-temperature systems within the scope of license renewal. The GALL Report AMP does not exclude non-Class 1 bolting.

The staff reviewed the Bolting Integrity Program, and its evaluation is documented in the Audit and Review Report. It was noted that the BSEP Bolting Integrity Program is claimed to be consistent with GALL AMP XI.M18; however, it has several major exceptions. For non-Class 1 pressure-retaining bolting, the BSEP AMP excludes the ASME Section XI inservice inspection activities, along with monitoring and trending under the Systems Monitoring Program.

This discrepancy was identified as part of the staff’s audit of the ESF systems. The staff requested that the applicant clarify how aging management of pressure-retaining bolting would be managed during the extended period of operation. In its response,the applicant committed to revise the Bolting Integrity Program to include those bolted connections outside of ASME Section XI boundaries (non-Class 1 pressure-retaining bolting) (see Commitment Item #3). In addition, the applicant committed to revise each applicable section of the LRA, including Section 3.4 on the steam and power conversion systems, to reflect this change in scope of the Bolting Integrity Program and address each of the aging effects identified in the GALL Report.

The staff determined that upon completion of the revisions noted above the Bolting Integrity Program will be consistent with the GALL Report for all pressure-retaining bolting. Structural bolting will not be addressed. Since BSEP treats bolting as a subcomponent of the pressure-retaining components, there are no separate AMRs for bolting in the steam and power conversion systems. However, the applicant’s commitment to specify the Bolting Integrity Program to manage all of the aging effects identified in the GALL Report for components containing Class 1 and non-Class 1 pressure-retaining bolting will resolve the above mentioned discrepancy.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.4.2.1.2 Loss of Material and Buildup of Deposits for Heat Exchangers, Coolers, and Condensers Serviced by Open-Cycle Cooling Water

In the discussion of LRA Table 3.4.1, item number 3.4.1-09, the applicant addressed loss of material due to corrosion and buildup of deposits due to biofouling for heat exchangers, coolers, and condensers serviced by open-cycle cooling water. The GALL Report recommends the Open-Cycle Cooling Water System Program to manage these aging effects. However, the applicant stated that management of these aging effects is not applicable to BSEP since the main condensers’ pressure boundary integrity is continuously confirmed through normal plant operation.

Therefore, the Open-Cycle Cooling Water System Program is not credited for managing aging effects/mechanisms for the main condensers.

As part of its AMR audit for the main condensers, the staff asked the applicant to justify its conclusion that no aging management program was required for these components. In response, the applicant stated that intended function, provide pressure-retaining boundary, was inappropriate for the main condenser and the LRA will be revised to reflect this.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.4.2.1.3 Loss of Material for Heat Exchangers, Coolers, and Condensers Serviced by Closed-Cycle Cooling Water

In the discussion section of LRA Table 3.4.1, item number 3.4.1-10, the applicant addressed loss of material due to corrosion for heat exchangers, coolers, and condensers that are serviced by closed-cycle cooling water. The applicant stated that item number 3.4.1-10 is not applicable to BSEP, since there are no heat exchangers and cooler/condensers serviced by closed-cycle cooling water. The staff agreed with the applicant's determination that the aging effects addressed by this item number are not applicable on the basis that the BSEP plant design eliminates any closed-cycle cooling water system components from the steam and power conversion systems.

3.4.2.1.4 Loss of Material for Piping and Fittings, and Valves in the Auxiliary Boiler System

In the discussion section of LRA Table 3.4.2-2, the applicant included AMR line items for piping and fittings, and valves in the auxiliary boiler system that are constructed of carbon steel and exposed to treated water. The One-Time Inspection Program is specified to manage loss of material due to crevice, general, and pitting corrosion for these components. GALL Report line item VIII.B2.1-a is referenced for the piping and fittings AMR, and VIII.B2.2-b is referenced for the valve AMR. However, both of the referenced GALL Report line items recommend GALL AMP XI.M2 to manage these aging effects.

The staff evaluated the applicant's use of the One-Time Inspection Program as an alternative to the Water Chemistry Program for managing the aging effects identified for the auxiliary boiler system. Through interviews with the applicant, the staff determined that although corrosion inhibitors are added to the water in the auxiliary boiler, the subject piping and valves are not under constant water chemistry control. The One-Time Inspection Program in GALL AMP XI.M32 states:

> There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly as not to affect the component or structure intended function. A one-time inspection of the subject component or structure is an acceptable option for this verification. One-time inspection is to provide additional assurance that either aging is not occurring or the evidence of aging is so insignificant that an aging management program is not warranted.

The staff also reviewed BSEP operating procedures, as documented in the Audit and Review Report. Based on the review of these documents, the staff determined that the auxiliary steam system is operated infrequently; there may be locations that are isolated from the flow stream for extended periods or that are susceptible to the gradual accumulation and concentration of agents that promote certain aging effects. The One-Time Inspection Program provides inspections that either verify the absence of aging degradation or trigger additional actions that will assure that the intended function of affected components will be maintained during the period of extended operation.

The staff determined that, since the GALL Report identifies the One-Time Inspection Program as an acceptable method for verifying the lack of an aging effect, or a slowly progressing aging effect, this AMP is acceptable for managing the aging effects for the auxiliary boiler system components. On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.4.2.1.5 Loss of Material for the Main Condenser in the Condensate System

In the discussion section of LRA Table 3.4.2-5, the applicant presented its AMR results for the main condenser system. Under the table subheading “Main Condenser,” the applicant claimed consistency with the GALL Report for aging management of the internal and external surfaces of the carbon steel condenser shell. Generic Note E is cited (component, material, environment consistent, different AMP). However, the applicant claimed that an AMP is not applicable, and referenced plant-specific Note 404. The staff noted that the applicant’s use of Note E for these AMR entries is questionable, because no AMP is credited.

The applicant’s justification for not specifying an AMP for these components is provided in plant-specific Note 404, which states that the integrity of the main condenser required to perform its post-accident intended function is continuously confirmed by normal plant operation; therefore, no traditional aging management program is required. The post-accident intended function of the main condensers is to provide a holdup volume and plateout surface for main steam isolation valve (MSIV) leakage. This intended function does not require the main condensers to be leak-tight, since the post-accident conditions in the main condensers are essentially atmospheric. Under post-accident conditions, there will be no challenge to the pressure boundary integrity of the main condensers. Since normal plant operation assures adequate main condenser pressure boundary integrity, the post-accident intended function to provide pressure boundary and holdup volume and plateout surface is assured.

During the audit, the staff evaluated the applicant’s justification and noted that SRP-LR Section A.1.2.3.4 states that a program based solely on detecting structure and component failures is not considered an effective aging management program. The staff requested that the applicant justify why monitoring main condenser integrity during normal plant operation is adequate as the only aging management program for ensuring intended functions identified, which are provide pressure-retaining boundary (M-1), and provide post-accident containment, holdup, and plateout of MSIV bypass leakage (M-7).

As documented in the Audit and Review Report, the applicant stated that the main condensers were placed within the scope of license renewal due to application of the alternate source term requirement. The applicant inadvertently assigned the intended function pressure boundary (M1) to the main condensers and associated components. The intended function M-7, which provides holdup and plateout of MSIV leakage, is the appropriate function for the main condensers in the alternate source term role; whereas, pressure boundary is not an appropriate intended function. LRA Tables 2.3.4-5 and 3.4.2-5 will be revised to show that the main condenser tubes, tube sheet, shell, and associated components have an intended function of M-7 only. The applicant also will revise LRA Table 3.4.1 Item Numbers 3.4.1-05 and 3.4.1-09, and LRA Section 3.4.2.2.4 by removing reference to the pressure boundary function of the main condenser. Additionally, the applicant will revise plant-specific Note 404 to remove the discussion of the pressure boundary function of the main condenser, and it will read as follows:

> Aging management of the Main Condensers is not based on analysis of materials, environments and aging effects. Materials, environments, and aging effects were evaluated, however no traditional aging management program is require. The Main Condenser is required to perform a post-accident intended function of holdup and plateout of MSIV leakage (M-7), and this function is continuously confirmed by normal plant operation. The M-7 intended function does not require the Main Condensers to be leak-tight, with the post-accident conditions in the Main Condenser essentially atmospheric. In maintaining vacuum, the Main Condenser proves its integrity continuously as a vital component of continued plant operation. Normal plant operation continuously monitors the integrity of the Main Condenser which provides assurance that the Main Condenser would be able to perform a post-accident intended function of holdup and plateout of MSIV leakage.

Based on the applicant’s statement that the only intended function for the main condensers is M-7, to provide post-accident containment, holdup, and plateout of MSIV bypass leakage, the staff agreed with the applicant’s determination that the main condenser does not have to be leak-tight, since the post-accident conditions in the main condenser are essentially atmospheric. During normal plant operations, condenser vacuum is continuously monitored, which verifies the integrity of the main condenser. If the integrity of the main condenser were to degrade to a point where a loss of vacuum occurred, this would require placing the plant in a mode where the M-7 intended function would be obviated. Therefore, acceptable performance during normal plant operation provides adequate assurance that the main condenser can perform the holdup and plate-out post-accident function.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

Conclusion. The staff evaluated the applicant’s claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant’s consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 AMR Results For Which Further Evaluation is Recommended By the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.4.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the steam and power conversion system. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- local loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling
- general corrosion
- loss of material due to general, pitting, and microbiologically influenced corrosion

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.4.2.2. Details of the staff's audit are documented in the staff's Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

Cumulative fatigue is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed by staff in SER Section 4.3.

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed the LRA Section 3.4.2.2.2 against the criteria found in SRP-LR Section 3.4.2.2.2:

> The management of loss of material due to general, pitting, and crevice corrosion should be evaluated further for carbon steel piping and fittings, valve bodies and bonnets, pump casings, pump suction and discharge lines, tanks, tubesheets, channel heads, and shells except for main steam system components and for loss of material due to pitting and crevice corrosion for stainless steel tanks and heat exchanger/cooler tubes. The water chemistry program relies on monitoring and control of water chemistry based on the guidelines in EPRI guideline TR-102134 for secondary water chemistry to manage the effects of loss of material due to general, pitting, or crevice corrosion. However, corrosion may occur at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion to verify the effectiveness of the water chemistry program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.4.2.2.2, the applicant stated that loss of material for carbon and stainless steel components in steam and power conversion systems (except for main steam system components) is managed by the Water Chemistry Program. Also, to verify the efficacy of that program, a one-time inspection of selected components and susceptible locations will be performed.

The staff found that, based on the programs identified above, the applicant met the criteria of SRP-LR Section 3.4.2.2.2 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Local Loss of Material Due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

Applicable to PWR auxiliary feedwater systems only.

3.4.2.2.4 General Corrosion

The staff reviewed LRA Section 3.4.2.2.4 against the criteria found in SRP-LR Section 3.4.2.2.4:

> Loss of material due to general corrosion could occur on the external surfaces of all carbon steel strictures and components, including closure boltings, exposed to operating temperature less that 212EF. The GALL Report recommends further evaluation to ensure that this aging effect is adequately managed.

In LRA Section 3.4.2.2.4, the applicant stated that loss of material for steel components, including closure bolting, in steam and power conversion systems due to general corrosion on external surfaces that are exposed to operating temperatures less than 212EF, is managed by the plant-specific Systems Monitoring Program. Management of aging effects/mechanisms associated with the main condensers is not applicable as the pressure boundary integrity of the main condensers is continuously confirmed through normal plant operations.

The applicant stated that it will revise LRA Section 3.4.2.2.4 to eliminate the reference to the pressure boundary function of the main condensers since this function is inappropriate for these components. Also, the applicant stated that the Bolting Integrity Program will be revised to include non-Class 1 pressure-retaining bolting, and the applicable LRA sections will be revised to reflect the change in scope of the AMP and the aging effects identified in the GALL Report for pressure-retaining bolting.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.4 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 Loss of Material Due to General, Pitting, and Microbiologically Influenced Corrosion

<u>PWR Auxiliary Feedwater System Lube Oil Coolers (LRA Section 3.4.2.2.5.1)</u>. Applicable to PWR auxiliary feedwater systems only.

Buried Components (LRA Section 3.4.2.2.5.2). Not applicable at BSEP since auxiliary feedwater is a PWR system.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant adequately addressed the issues that were further evaluated. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3 Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.4.2-1 through 3.4.2-7, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.4.2-1 through 3.4.2-7, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report, and it provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line-item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line-item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line-item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line-item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combination that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.4.2.3.1 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Main Steam (MS) System – Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Section 3.4.2.1.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the main steam system components:

- Water Chemistry Program
- Flow-Accelerated Corrosion Program

In LRA Table 3.4.2-1, the applicant provided a summary of the AMRs for the system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the main steam system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.4.2-1. The staff also reviewed those combinations in LRA Table 3.4.2-1, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.4-1 lists individual system components within the scope of license renewal and subject to an AMR. The component types that do not rely on the GALL Report for aging management review are piping and fittings, and valves.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (includes steam)(internal) environments are subject to loss of material due to general corrosion.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion.
- Stainless steel and carbon steel components in indoor air (external) environments are not identified with any AERMs.

During its review, the staff determined that it needed additional information. The specific RAI and the applicant's response are discussed below.

In RAI 3.4-1, dated April 8, 2005, the staff stated that in LRA Tables 3.4.2-1 and 3.4.2-6, stainless steel piping and fitting (steam drains) and valves in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion. The Water Chemistry Program alone is credited to manage the aging effects. The staff considered this to be unacceptable, since, for the BWR plant components in the above identified environments, the AMP needs to be augmented by verifying the effectiveness of water chemistry control. Therefore, the staff requested that the applicant reassess the AMR for the components. In its response, by letter dated May 4, 2005, the applicant stated that stainless steel components represented by the Table 3.4.2-1 subject line items are NSR orifice plates and instrumentation components. Stainless steel components represented by the LRA Table 3.4.2-6 subject line items are NSR stainless steel tubing. The applicant stated that to verify the effectiveness of water chemistry control for these stainless steel components, the Water Chemistry Program will be augmented by using the One-Time Inspection Program. The staff found that the applicant's response adequately resolved the staff's concern related to the implementation of a verification program; therefore, RAI 33.4-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the main steam system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the main steam system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-1 identifies the following AMPs for managing the aging effects described above for the main steam system.

- Water Chemistry Program
- Flow-Accelerated Corrosion Program

SER Sections 3.0.3.2.1 and 3.0.3.2.2, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the main steam system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.4.2.3.2 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Auxiliary Boiler – Table 3.4.2-2

The staff reviewed LRA Table 3.4.2-2, which summarizes the results of AMR evaluations for the auxiliary boiler component groups.

In LRA Section 3.4.2.1.2, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERM for the auxiliary boiler system components:

- One-Time Inspection Program
- Systems Monitoring Program

In LRA Table 3.4.2-2, the applicant provided a summary of the AMRs for the auxiliary boiler system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the auxiliary boiler system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.4.2-2. The staff also reviewed those combinations in LRA Table 3.4.2-2, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.4-2 lists individual system components within the scope of license renewal and subject to an AMR. The following component types do not rely on the GALL Report for an AMR: piping and fittings, and valves.

For this component type, the applicant identified the material, environment, and AERM, as specified below:

- Carbon steel components in treated water (includes steam)(internal) environments are subject to loss of material due to crevice, general, and pitting corrosion.

During its review, the staff determined that it needed additional information to complete its review. The specific RAI and the applicant's response are discussed below.

In RAI 3.4-2, dated April 8, 2005, the staff stated that In LRA Table 3.4.2-2, carbon steel piping and fittings (steam drains) and valves in treated water (includes steam)(internal) environments are subject to loss of material due to general, crevice, and pitting corrosion. The One-Time Inspection Program is credited as the only AMP to manage the aging effects. It should be noted that one-time inspections may be appropriate only for situations where material degradation is not expected or is expected to occur at a slow rate. One-time inspections can also be used to verify the effectiveness of an AMP in its management of aging effects. Therefore, the staff requested that the applicant provide justification for not using a periodic inspection program, supplemented by the One-Time Inspection Program, to manage the aging effects for the above carbon steel components. In its response, by letter dated May 4, 2005, the applicant stated that the components represented by LRA Table 3.4.2-2 subject line items are NSR auxiliary boiler system piping components and valves within scope for potential spatial interactions. The auxiliary boiler system is a unit-sharing system that provides steam to both Units 1 and 2 for HPCI and RCIC turbine testing prior to unit startup. The applicant stated that this auxiliary steam piping is only used infrequently for unit startup at the HPCI and RCIC turbines located in the reactor building. This piping is routed through the radwaste building tunnels into the reactor building. After the HPCI and RCIC turbines are tested during unit startup, the subject steam supply piping in the tunnels and reactor building are de-pressurized and isolated from the auxiliary boiler.

The applicant stated that the GALL XI.M32, One-Time Inspection AMP is appropriate for the subject auxiliary boiler piping components. The one-time inspection provides inspections that either verify that unacceptable degradation is not occurring or trigger additional actions that will assure that the intended function of affected components will be maintained during the period of extended operation. The applicant stated that the BSEP One-Time Inspection Program will verify that the expectation of potential aging effects occurring very slowly so as not to affect the component intended function during the period of extended operation is correct or will verify the extent of condition for subsequent corrective actions.

Based on the fact that the subject in-scope auxiliary boiler system piping components and valves are infrequently used and isolated from the auxiliary boiler after usage, with piping that is de-energized and drained or partially drained, the staff considered the applicant's response to be acceptable; the use of One-Time Inspection Program is appropriate for the subject auxiliary boiler piping components. Therefore, the staff's concern described in RAI 3.4-2 is resolved. SER Section 3.0.3.15 provides additional staff discussion on the One-Time Inspection Program.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the auxiliary boiler system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the auxiliary boiler system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-2 identifies the following AMPs for managing the aging effects described above for the auxiliary boiler system.

- One-Time Inspection Program
- Systems Monitoring Program

SER Sections 3.0.3.2.11 and 3.0.3.3.2, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant described the appropriate AMPs for managing the aging effect of the auxiliary boiler system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.4.2.3.3 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Feedwater (FW) System – Table 3.4.2-3

The staff reviewed LRA Table 3.4.2-3, which summarizes the results of AMR evaluations for the feedwater system component groups.

In LRA Section 3.4.2.1.3, the applicant identified materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the feedwater system components:

- Water Chemistry Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program

In LRA Table 3.4.2-3, the applicant provided a summary of the AMRs for the feedwater system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the feedwater system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.4.2-3. The staff also reviewed those combinations in LRA Table 3.4.2-3, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.4-3 lists individual system components within the scope of license renewal and subject to an AMR. The following component types do not rely on the GALL Report for aging management review: piping and fittings, and valves.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion.
- Stainless steel and carbon steel components in indoor air (external) environments are not identified with any aging effects.

On the basis of its review of the information provided in the LRA, the staff found that the aging effects of the feedwater system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the feedwater system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-3 identifies the following AMPs for managing the aging effects described above for the feedwater system.

- Water Chemistry Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program

SER Sections 3.0.3.2.1, 3.0.3.2.2, and 3.0.3.2.11, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the feedwater system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.4.2.3.4 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Heater Drains (HD) and Miscellaneous Vents and Drains (MVD) – Table 3.4.2-4

The staff reviewed LRA Table 3.4.2-4, which summarizes the results of AMR evaluations for the HD and MVD component groups.

In LRA Section 3.4.2.1.4, the applicant identified materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the HD and MVD system components:

- Water Chemistry Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program

In LRA Table 3.4.2-4, the applicant provided a summary of the AMRs for the HD and MVD system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the HD and MVD system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.4.2-4. The staff also reviewed those combinations in LRA Table 3.4.2-4, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

<u>Aging Effects</u>. LRA Table 2.3.4-4 lists individual system components within the scope of license renewal and subject to an AMR. The following component types do not rely on the GALL Report for AMR: piping and fittings, and valves.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in indoor air (internal) environments are subject to loss of material due to general corrosion.
- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion.
- Stainless steel and carbon steel components in indoo0r air (external) environments are not identified with any aging effects.

On the basis of its review of the information provided in the LRA, the staff found that the aging effects of the HD and MVD system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the HD and MVD system.

<u>Aging Management Programs</u>. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-4 identifies the following AMPs for managing the aging effects described above for the HD and MVD system.

- Water Chemistry Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program

SER Sections 3.0.3.2.1, 3.0.3.3.2, 3.0.3.2.11, and 3.0.3.3.2, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the HD and MVD system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.4.2.3.5 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Condensate System – Table 3.4.2-5

The staff reviewed LRA Table 3.4.2-5, which summarizes the results of AMR evaluations for the condensate system component groups.

In LRA Section 3.4.2.1.5, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the condensate system components:

- Water Chemistry Program
- Aboveground Carbon Steel Tanks Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Buried Piping and Tanks Inspection Program
- Systems Monitoring Program

In LRA Table 3.4.2-5, the applicant provided a summary of the AMRs for the condensate system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the condensate system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.4.2-5. The staff also reviewed those combinations in LRA Table 3.4.2-5, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.4-5 lists individual system components within the scope of license renewal and subject to an AMR. The following component types do not rely on the GALL Report for AMR: piping and fittings, valves, tanks, tubes, tubesheets, and shells.

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Carbon steel components in treated water (internal) environments are subject to loss of material due to galvanic corrosion.
- Carbon steel components in indoor air (external) and outdoor air (external) environments are subject to loss of material due to general corrosion.
- Stainless steel components in treated water (internal) environments are subject to loss of material due to erosion.
- Stainless steel components in buried (external) environments are subject to loss of material due to crevice and pitting corrosion, and MIC.
- Stainless steel components in outdoor air (external) environments are subject to loss of material due to crevice and pitting corrosion.
- Grey cast iron components in treated water (internal) or outdoor air (external) environments are subject to loss of material due to selective leaching.
- Grey cast iron components in treated water (internal) environments are subject to loss of material due to galvanic, crevice, general, and pitting corrosion.
- Grey cast iron components in outdoor air (external) environments are subject to loss of material due to galvanic and general corrosion.
- Stainless steel and carbon steel components in indoor air (internal or external) environments are not identified with any aging effects.

During its review, the staff determined that it needed additional information to complete its review. The specific RAI and the applicant's response are discussed below.

In RAI 3.4-4, dated April 8, 2005, the staff stated that in LRA Table 3.4.2-5, titanium condensate coolers/condensers (tubes) in raw water environments are not identified with any aging effects. The same components in treated water (including steam)(external) environments are subject to loss of material due to crevice corrosion. Therefore, the staff requested that the applicant provide the basis for determining that no aging effects need to be identified for the titanium condensate coolers/condensers (tubes) in raw water environments. In its response, by letter dated May 4, 2005, the applicant stated that the BSEP mechanical tools for assessing aging effects are based on industry guidance, EPRI TR-1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3." The applicant stated that the subject titanium condensate coolers/condensers (tubes) in treated water environments are normally at a temperature greater than 160EF. The titanium condensate coolers/condensers (tubes) in a raw water environments are normally at a temperature less than 160EF. The applicant stated that, based on the referenced EPRI document, the BSEP mechanical tools identified that titanium in raw water at a temperature less than 160EF does not exhibit aging effects, while titanium in treated water at a temperature of greater than 160EF is potentially subject to aging effects. The staff considered the applicant's response incorporating general industry experience to be acceptable; therefore, RAI 3.4-4 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the condensate system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the condensate system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-5 identifies the following AMPs for managing the aging effects described above for the condensate system.

- Water Chemistry Program
- Aboveground Carbon Steel Tanks Program
- One-Time Inspection Program
- Selective Leaching of Materials Program
- Buried Piping and Tanks Inspection Program
- Systems Monitoring Program

SER Sections 3.0.3.2.1, 3.0.3.1.4, 3.0.3.2.11, 3.0.3.2.12, 3.0.3.2.13, and 3.0.3.3.2, respectively, present the staff's detailed review of these AMPs.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described appropriate AMPs for managing the aging effect of the condensate system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.4.2.3.6 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Turbine Building (TB) Sampling System – Table 3.4.2-6

The staff reviewed LRA Table 3.4.2-6, which summarizes the results of AMR evaluations for the turbine building sampling system component groups.

In LRA Section 3.4.2.1.6, the applicant identified the materials, environments, and AERMs. The applicant identified the Water Chemistry Program to manage the aging effects for the turbine building sampling system components.

In LRA Table 3.4.2-6, the applicant provided a summary of the AMRs for the turbine building sampling system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant's AMR of the turbine building sampling system component-material-environment-AERM combinations that are not addressed in the GALL Report. These combinations are identified by Notes F through J in LRA Table 3.4.2-6. The staff also reviewed those combinations in LRA Table 3.4.2-6, with Notes A through E, for which issues were identified. The staff determined that the applicant has identified all applicable AERMs and credited appropriate AMPs for managing them. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions are adequate.

Aging Effects. LRA Table 2.3.4-6 lists individual system components within the scope of license renewal and subject to an AMR. The following component types do not rely on the GALL Report for AMR: piping and fittings (steam drains).

For these component types, the applicant identified the materials, environments, and AERMs, as specified below:

- Stainless steel components in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion.
- Stainless steel components in indoor air (external) environments are not identified with any aging effects.

During its review, the staff determined that it needed additional information to complete its review. The specific RAI and the applicant's response are discussed below.

In LRA Table 3.4.2-6, stainless steel piping and fitting (steam drains) and valves in treated water (includes steam)(internal) environments are subject to cracking due to SCC, and loss of material due to crevice and pitting corrosion. The Water Chemistry Program alone is credited to manage the aging effects. The staff considered this to be unacceptable, since for the BWR plant components in the above identified environments, the AMP needs to be augmented by verifying the effectiveness of water chemistry control. In RAI 3.4-1, the staff requested the applicant to reassess the AMR for the components. SER Section 3.4.2.3.1 provides the staff's discussion of this RAI and its resolution by the applicant.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found that the aging effects of the turbine building sampling system component types not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the turbine building sampling system.

Aging Management Programs. After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-6 identifies the Water Chemistry Program and One-Time Inspection Program for managing the aging effects described above for the turbine building sampling system. SER Section 3.0.3.2.1 presents the staff's detailed review of this AMP.

On the basis of its review of the information provided in the LRA, the staff found that the applicant has described an appropriate AMP for managing the aging effects of the turbine building sampling system component types not addressed by the GALL Report. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.4.2.3.7 Steam and Power Conversion Systems – Summary of Aging Management Evaluation – Main Condenser Gas Removal System – Table 3.4.2-7

The staff reviewed LRA Table 3.4.2-7, which summarizes the results of AMR evaluations for the main condenser gas removal system component groups.

In LRA Section 3.4.2.1.7, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the AERMs for the main condenser gas removal system components:

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

In LRA Table 3.4.2-7, the applicant provided a summary of the AMRs for the main condenser gas removal system components and identified which AMRs it considered to be consistent with the GALL Report.

The technical staff reviewed the applicant’s AMR of the main condenser gas removal system component-material-environment-AERM combinations that are not addressed in the GALL Report. The staff noted no such combinations, identified by Notes F through J, in LRA Table 3.4.2-7; therefore, no AERMs are identified. The staff also reviewed those combinations in LRA Table 3.4.2-7, with Notes A through E, for which issues were identified.

Aging Effects. LRA Table 2.3.4-7 lists individual system components within the scope of license renewal and subject to an AMR. Since there are no component types that are considered to not rely on the GALL Report for aging management review, there are no AERMs specified in the table.

Aging Management Programs.

After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR supplement contains an adequate description of the program.

LRA Table 3.4.2-7 identifies the following AMPs for managing the aging effects described above for the main condenser gas removal system.

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

As indicated, these AMPs are credited to manage the aging effects of all three main condenser gas removal system component types contained in LRA Table 3.4.2-7. According to the system generic notes, all these component types are addressed by the GALL Report. SER Sections 3.0.3.2.1, 3.0.3.2.11, and 3.0.3.3.2, respectively, present the staff's detailed review of these AMPs.

Conclusion. On the basis of its review, the staff found that the applicant appropriately evaluated AMR results involving material, environment, AERMs, and AMP combinations not evaluated in the GALL Report. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging for the of the steam and power conversion system components, that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the steam and power conversion system, as required by 10 CFR 54.21(d).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containments, structures, and component supports components and component groups associated with the following systems:

- containment
- intake and discharge canals
- refueling system
- switchyard and transformer yard structures
- monorail hoists
- bridge cranes
- gantry cranes
- service water intake structure
- reactor building
- augmented off-gas building
- diesel generator building
- control building
- turbine building
- radwaste building
- water treatment building
- miscellaneous structures and out-buildings

3.5.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant provided AMR results for components. In LRA Table 3.5.1, "Summary of Aging Management Evaluations in Chapters II and III of NUREG-1801 for Containments, Structures, and Component Supports," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the containments, structures, and component supports components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the containments, structures, and component supports components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the Audit and Review Report and are summarized in SER Section 3.5.2.1.

During the audit, the staff reviewed the AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in the GALL Report, Section 3.5.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.5.2.2.

During the audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating (1) whether all plausible aging effects were identified, and (2) whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.5.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.5.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the containments, structures, and component supports components.

Table 3.5-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5, that are addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Containments, Structures, and Component Supports in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Common Components of All Types of PWR and BWR Containment				
Penetration sleeves, penetration bellows, and dissimilar metal welds (Item Number 3.5.1-01)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1-02)	Cracking due to cyclic loading, or crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	ASME Section XI, Subsection IWE Program (B.2.18); 10 CFR Part 50, Appendix J Program (B.2.21)	Not consistent with GALL (See Section 3.5.2.2.1.7)
Penetration sleeves, penetration bellows, and dissimilar metal welds (Item Number 3.5.1-03)	Loss of material due to corrosion	Containment ISI and Containment leak rate test	ASME Section XI, Subsection IWE Program (B.2.18); 10 CFR Part 50, Appendix J Program (B.2.21)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1-04)	Loss of material due to corrosion	Containment ISI and Containment leak rate test	ASME Section XI, Subsection IWE Program (B.2.18); 10 CFR Part 50, Appendix J Program (B.2.21)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1-05)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanism	Containment leak rate test and Plant Technical Specifications	10 CFR Part 50, Appendix J Program (B.2.21); BSEP Units 1 and 2 Technical Specifications for Containment Systems	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Seals, gaskets, and moisture barriers (Item Number 3.5.1-06)	Loss of sealant and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers	Containment ISI and Containment leak rate test	ASME Section XI, Subsection IWE Program (B.2.18); 10 CFR Part 50, Appendix J Program (B.2.21)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
PWR Concrete (Reinforced and Prestressed) and Steel Containment BWR Concrete (Mark II and III) and Steel (Mark I, II, and III) Containment				

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Concrete elements: foundation, walls, dome (Item Number 3.5.1-07)	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI	ASME Section XI, Subsection IWL Program (B.2.19)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.1)
Concrete elements: foundation (Item Number 3.5.1-08)	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	Structures Monitoring Program (B.2.23)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Concrete elements: foundation (Item Number 3.5.1-09)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	N/A	Not applicable (See Section 3.5.2.2.1.2)
Concrete elements: foundation, dome, and wall (Item 3.5.1-10)	Reduction of strength and modulus due to elevated temperature	Plant specific		Not consistent with GALL (See Section 3.5.2.2.1.3)
Prestressed containment: tendons and anchorage components (Item 3.5.1-11)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)		Not Applicable (See Section 3.5.2.2.1.5)
Steel elements: liner plate, containment shell (Item 3.5.1-12)	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI and Containment leak rate test	ASME Section XI, Subsection IWE Program (B.2.18); 10 CFR Part 50, Appendix J Program (B.2.21)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.1)
Steel elements: vent header, drywell head, torus, downcomers, pool shell (Item 3.5.1-13)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3
Steel elements: protected by coating (Item3.5.1-14)	Loss of material due to corrosion in accessible areas only	Protective coating monitoring and maintenance	N/A	Not applicable

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Prestressed containment: tendons and anchorage components (Item 3.5.1-15)	Loss of material due to corrosion of prestressing tendons and anchorage components	Containment ISI	N/A	Not applicable
Concrete elements: foundation, dome, and wall (Item 3.5.1-16)	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI	ASME Section XI, Subsection IWL Program (B.2.19)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1.1)
Steel elements: vent line bellows, vent headers, downcomers (Item 3.5.1-17)	Cracking due to cyclic loads or Crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	ASME Section XI, Subsection IWE Program (B.2.18); 10 CFR Part 50, Appendix J Program (B.2.21)	Not consistent with GALL (See Section 3.5.2.2.1.7)
Steel elements: Suppression chamber liner (Item 3.5.1-18)	Crack initiation and growth due to SCC	Containment ISI and Containment leak rate test		Not applicable
Steel elements: drywell head and downcomer pipes (Item 3.5.1-19)	Fretting and lock up due to wear	Containment ISI		Not applicable (See Section 3.5.2.1.2)
Class I Structures				
All Groups except Group 6: accessible interior/exterior concrete steel & components (Item 3.5.1-20)	All types of aging effects	Structures Monitoring	Structures Monitoring Program (B.2.23)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 7-9: inaccessible concrete components, such as exterior walls below grade and foundation (Item 3.5.1-21)	Aging of inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	Plant specific	Structures Monitoring Program (B.2.23)	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.2.2)
Group 6: all accessible/ inaccessible concrete, steel, and earthen components (Item 3.5.1-22)	All types of aging effects, including loss of material due to abrasion, cavitation, and corrosion	Inspection of Water-Control Structures or FERC/US Army Corp of Engineers dam inspection and maintenance	Structures Monitoring Program (B.2.23)	Not consistent with GALL (See Section 3.5.2.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Group 5: liners (Item Number 3.5.1-23)	Crack initiation and growth from SCC and loss of material due to crevice corrosion	Water Chemistry Program and Monitoring of spent fuel pool water level	Water Chemistry Program (B.2.2); Technical Specifications	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 6: all masonry block walls (Item 3.5.1-24)	Cracking due to restraint, shrinkage, creep, and aggressive environment	Masonry Wall	Masonry Wall Program (B.2.22)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 7-9: foundation (Item 3.5.1-25)	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	Structures Monitoring Program (B.2.23)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1-3, 5-9: foundation (Item 3.5.1-26)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	N/A	Not applicable
Groups 1-5: concrete (Item 3.5.1-27)	Reduction of strength and modulus due to elevated temperature	Plant-specific		Not consistent with GALL (See Section 3.5.2.2.1.3)
Groups 7, 8: liners (Item 3.5.1-28)	Crack Initiation and growth due to SCC; Loss of material due to crevice corrosion	Plant-specific	N/A	Not applicable
Component Supports				
All Groups: support members: anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc. (Item 3.5.1-29)	Aging of component supports	Structures Monitoring	Structures Monitoring Program (B.2.23)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds (Item 3.5.1-30)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
All Groups: support members: anchor bolts, welds (Item 3.5.1-31)	Loss of material due to boric acid corrosion	Boric acid corrosion	N/A	Not applicable
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds, spring hangers, guides, stops, and vibration isolators (Item 3.5.1-32)	Loss of material due to environmental corrosion; loss of mechanical function due to corrosion, distortion, dirt, overload, etc.	ISI	ASME Section XI, Subsection IWF Program (B.2.20)	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Group B1.1: high strength low-alloy bolts (Item 3.5.1-33)	Crack initiation and growth due to SCC	Bolting integrity	N/A	Not applicable

The staff's review of the BSEP component groups followed one of three approaches depending on the group's consistency with the GALL Report. SER Section 3.5.2.1 discusses the staff's review and documentation of the AMR results for components associated with containments, structures, and component supports that the applicant indicated are consistent with the GALL Report and do not require further evaluation; SER Section 3.5.2.2 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended; and, Section 3.5.2.3 discusses the staff's review and documentation of the AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the containment, structures, and component supports components is documented in SER Section 3.0.3.

3.5.2.1 AMR Results That Are Consistent with the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.5.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the containments, structures, and component supports components:

- Structures Monitoring Program
- ASME Section XI, Subsection IWE Program
- ASME Section XI, Subsection IWL Program
- ASME Section XI, Subsection IWF Program
- 10 CFR Part 50, Appendix J Program
- Water Chemistry Program
- Inspection of Overhead Heavy Load and Light Load Handling Systems
- Masonry Wall Program
- Fire Protection Program
- Fuel Pool Girder Tendon Monitoring Program

Staff Evaluation. In LRA Tables 3.5.2-1 through 3.5.2-15, the applicant provided a summary of AMRs for the containments, structures, and component supports components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

In the LRA Section 3.5, the applicant provided the results of its AMRs for containments, structures, and component supports.

In LRA Tables 3.5.2-1 through 3.5.2-15, the applicant provided a summary of the AMR results for components/commodities in the (1) primary containment; (2) intake and discharge canals; (3) refueling system; (4) switchyard and transformer yard structures; (5) bridge cranes; (6) gantry cranes; (7) service water intake structure; (8) reactor building; (9) augmented off-gas building; (10) diesel generator building; (11) control building; (12) turbine building; (13) radwaste building; (14) water treatment building; and (15) miscellaneous structures and out-buildings.

Also, for each component type in LRA Table 3.5.1, the applicant identified those components that are consistent with the GALL Report, those that are consistent with the GALL Report in which further evaluation is recommended, and those that are not addressed in the GALL Report together with the basis for their exclusion.

For aging management evaluations that the applicant stated are consistent with the GALL Report, the staff conducted its audit to determine if the applicant's reference to the GALL Report in the LRA is acceptable.

The staff reviewed its assigned LRA line items to determine that the applicant : (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the primary containment, intake and discharge canals, refueling system, switchyard and transformer yard structures, bridge cranes, gantry cranes, service water intake structure, reactor building, augmented off-gas building, diesel generator building, control building, turbine building, radwaste building, water treatment building, and miscellaneous structures and out-buildings components that are subject to an AMR.

3.5.2.1.1 Loss of Material due to Wear and Corrosion for Rails in Load Handling Systems

LRA Tables 3.5.2-3, 3.5.2-5, and 3.5.2-6 each include an AMR line item for loss of material due to wear of rails in load handling systems. The AMRs reference GALL line item VII.B.2-a, Table 1 item 3.3.1-16, and generic Note A. The staff noted that GALL line item VII.B.2-a lists a specific grade of corrosion-resistant steel, ASTM A759 commonly used for crane rails. The applicant's AMRs identify the material as "carbon steel." During the audit, the staff noted that carbon steel would also be susceptible to loss of material due to corrosion. The staff asked the applicant to confirm that the crane rail material used at BSEP is grade A759 or equivalent. In its response the applicant confirmed that the crane rail material used at BSEP for the reactor building crane and the intake structure gantry crane meets the specifications for grade A759 crane rail steel. The crane rail material used for the refueling platform meets the specifications for ASTM A1, which is a corrosion-resistant steel commonly used in railroad applications and is considered equivalent to A-759. On this basis, the staff concluded that the crane rail materials used at BSEP are consistent with the material specified in the GALL Report.

The staff also noted that in LRA Table 3.5.2-6, the AMR line item for the rails of the intake structure gantry crane identifies the environment as "exposed to weather." GALL line item VII.B.2-a lists the environment as "air at 100 percent relative humidity and 49 EC (120 EF)," which is representative of design conditions inside containment. The staff also asked the applicant to provide its technical basis for concluding that the rails of the intake structure gantry crane in an "exposed to weather" environment are not susceptible to loss of material due to corrosion. In its response, the applicant stated that grade A759 crane rail steel has a long history of outdoor use without significant corrosion. In addition, BSEP's operating experience review has not identified corrosion as an issue for crane rails. The staff agreed with the applicant's assessment that corrosion is not a concern for A759 exposed to weather.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

3.5.2.1.2 Fretting and Lock Up Due to Wear for Drywell Head and Downcomer Pipes

LRA Table 3.5.1, Item 3.5.1-19, identifies steel elements: drywell head and downcomer pipes; fretting and lock-up due to wear as the aging effect/mechanism; and containment ISI as the AMP. In the discussion column for item 3.5.1-19 in LRA Table 3.5.1, the applicant stated:

> During normal operating conditions, the Primary Containment Drywell Head and Downcomers are not in contact with other components that could expose them to wear. However, during refueling operations, rubbing contact is possible during removal and reinstallation of the Drywell Head. Drywell Head movement is strictly controlled by procedure; therefore, loss of material due to wear is considered to be negligible.

The staff noted that there are no AMR entries in LRA Table 3.5.2-1 (containment) that reference LRA Table 3.5.1, item 3.5.1-19. During the audit, the staff asked the applicant to provide its AMR results for this component-aging effect combination, and to address whether the ASME Section XI, Subsection IWE Program is credited for aging management of fretting and lock-up due to wear.

In its response, the applicant stated that

> All items in Table 3.5.1 were addressed in the LRA and an explanation provided in the discussion section, regardless of whether the aging effect was considered applicable. The discussion associated with item 3.5.1-19 explains the effect is considered negligible and that is why it was not addressed within Table 3.5.2-1.
>
> Although the IWE program is not credited for management of "fretting and lock-up due to wear" for the subject components; it is credited for "Loss of Material", which effectively envelops wear. As such, management of the subject components by IWE is considered sufficient.

The staff agreed that the applicant's ASME Section XI, Subsection IWE Program will provide adequate aging management of fretting and lock-up due to wear for the drywell head and downcomer pipes, and determined that the applicant's response is acceptable.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 AMR Results For Which Further Evaluation is Recommended By the GALL Report

Summary of Technical Information in the Application. In LRA Section 3.5.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the containments, structures, and component supports. The applicant provided information concerning how it will manage the following aging effects:

- PWR and BWR containments
- Class 1 structures
- component supports

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.5.2.2 of the SRP-LR. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

3.5.2.2.1 PWR and BWR Containments

Aging of Inaccessible Concrete. The staff reviewed LRA Section 3.5.2.2.1.1 against the criteria found in SRP-LR Section 3.5.2.2.1.1:

> Cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in inaccessible areas of PWR concrete and steel containments; BWR Mark II concrete containments; and Mark III concrete and steel containments. The GALL Report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

In LRA Section 3.5.2.2.1.1, the applicant stated that the aging mechanisms of leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel are not significant for the concrete components of the primary containment structure. The BSEP primary containment is completely contained within the reactor building; therefore, it is not subject to aging effects associated with a below-grade, exterior environment. The primary containment concrete is not exposed to an aggressive environment and has been designed in accordance with ACI 318, with a low water/cement ratio and entrained air between 3 and 6 percent. Therefore, the aging mechanism of leaching of calcium hydroxide, which becomes significant only if the concrete is subject to flowing water, is not applicable. Also, aggressive chemical attack and corrosion of embedded steel are not applicable because the concrete is not exposed to aggressive chemicals.

The staff noted that the Mark I concrete containment design is unique. However, similar to Mark I steel containments, it is completely enclosed by the reactor building, and it is protected from the adverse environments that potentially cause age-related degradation of inaccessible concrete. The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.1 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracking, Distortion, and Increase in Component Stress Level Due to Settlement; Reduction of Foundation Strength Due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program</u>. The staff reviewed LRA Section 3.5.2.2.1.2 against the criteria found in SRP-LR Section 3.5.2.2.1.2:

> Cracking, distortion, and increase in component stress level due to settlement could occur in PWR concrete and steel containments and BWR Mark II concrete containments and Mark III concrete and steel containments. Also, reduction of foundation strength due to erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. Some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system, the GALL Report recommends verification of the continued functionality of the de-watering system during the period of extended operation. The GALL Report recommends no further evaluation if this activity is included in the scope of the applicant's structures monitoring program.

In LRA Section 3.5.2.2.1.2, the applicant stated that settlement was monitored during construction of BSEP, and the predicted settlement values were found to be consistent with that actually experienced. Plant engineers monitor for the effects of differential settlement during inspections of structures under the Structures Monitoring Program. A review of plant operating history has not identified any settlement issues. BSEP structures do not have porous concrete subfoundations and do not employ a de-watering system. Furthermore, the primary containment concrete is not in contact with the soil or groundwater. Therefore, reduction of foundation strength due to erosion of porous concrete is not an applicable aging effect.

During the audit the staff determined the applicant's further evaluation to be acceptable, on the basis that the effects of differential settlement of BSEP structures is monitored during inspections under the Structures Monitoring Program; BSEP does not have porous concrete subfoundations; and does not employ a de-watering system.

On the basis of its review, the staff found that the applicant appropriately addressed the aging mechanism, as recommended by the GALL Report.

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria found in SRP-LR Section 3.5.2.2.1.3:

> Reduction of strength and modulus of elasticity due to elevated temperatures could occur in PWR concrete and steel containments and BWR Mark II concrete containments and Mark III concrete and steel containments. The GALL Report recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits, i.e., general area temperature 66°C (150°F) and local area temperature 93°C (200°F).

In LRA Section 3.5.2.2.1.3, the applicant stated that elevated temperatures above the limits specified in the GALL Report are not applicable for concrete structures and components outside the primary containment. Inside the primary containment structure, the bulk average temperature is less than 150 EF; however, data for the confined, upper elevations of the primary containment have identified a maximum average temperature of 194 EF. Based on an evaluation of drywell temperatures, the contact temperature at the inside face of the concrete (drywell side) is approximately 175 EF and the contact temperature at the outside face of the concrete (reactor building side) is approximately 107 EF. Because the elevated temperatures are localized to the confined upper elevation of the drywell and the actual concrete temperatures are on a gradient through the drywell wall, the upper elevation of the drywell is considered a local rather than a general area. Therefore, the containment concrete elements are exposed to temperatures consistent with the guidance provided in the GALL Report, which defines elevated temperatures as greater than 150 EF general and 200 EF local; and the primary containment concrete is not subject to degradation due to elevated temperature.

During the audit, the staff requested that the applicant provide the detailed technical basis for this conclusion, including the results of heat transfer and thermal stress analyses, if available. In its response, the applicant stated:

> The BSEP containment bulk average temperature is maintained below 150 EF and is managed by Technical Specifications Section 3.6.1.4, which require the plant enter LCO actions if the drywell bulk average temperature exceeds 150 EF.
>
> The geometry of the BSEP drywell is such that the confined upper elevations will experience temperatures in excess of 150 EF. However the increased temperatures are only present in the very upper regions of the drywell; as such only the pressure boundary concrete walls, as discussed in GALL Chapter II, of the drywell are subject to the higher temperatures. Plant-specific note 536 was provided to explain this condition. The interior containment concrete addressed under GALL item III.A4.1-c is below the area of increased temperature and therefore not subject to the elevated temperatures, which is why plant specific note 513 is only associated with the interior concrete of GALL Chapter III.A4.
>
> A technical evaluation of the temperature gradient through the drywell wall determined interior concrete temperatures based on varying values of ambient drywell temperatures. Based on the results of that evaluation, using the maximum upper drywell ambient air temperature of 194 degrees F (based on local monitoring), the concrete surface

temperature is approximately 175 degrees F. The temperature gradient through the drywell wall was determined to be approximately 68 degrees F. Based on the temperature gradient of 68 degrees F and a drywell wall thickness of four feet, the internal concrete temperature would fall below 150 degrees F approximately 18 inches from the inside surface of the drywell wall. The concrete contact temperature of 175 degrees in the upper elevations is well below the "local" areas temperature limit of 200 degrees and drops off to a contact temperature of 150 degrees F within twenty feet of the upper elevations.

ACI 349 provides no basis for how local areas are defined and only provides the following statement for guidance: "such as around penetrations." The drywell concrete subject to temperatures in excess of 150EF is limited to less than half the wall thickness and is confined to the very upper elevations. The basis for "local" consideration is the fact that only a limited portion of the concrete cross-section is subject to temperatures over 150E, not the entire section, which is similar to the temperature gradient surrounding a penetration. As such, the very upper elevations of the drywell would effectively mimic a large penetration and would therefore be categorized as a local area.

However, the drywell concrete has been evaluated for the effects of increased temperature and was found to be acceptable. The evaluation considered drywell concrete temperature to be 185EF with a linear temperature gradient between the interior and exterior surfaces of approximately 70EF.

Summary of the evaluation results are as follows:

The states of stress in liner, rebar and concrete are well within allowable for the normal operating condition and are not significantly different for the design accident conditions.

Reductions in strength and modulus may occur at elevated temperature and can conservatively be accounted for by reduction factors on allowable stresses. The physical state of the concrete at 175EF to 185EF will not be significantly different from the ASME code limit 150EF.

There is no compromise of the containment's integrity under design accident conditions.

The staff reviewed the applicant’s response and determined that any reduction in strength and modulus of concrete resulting from sustained temperatures between 150EF and 175EF in the localized area of concrete at the upper elevation of the drywell would be minimal and will not compromise the structural integrity of the containment structure under design accident conditions. The staff noted that the concrete area in question is inaccessible for inspection because it is behind the steel liner. Therefore, the applicant appropriately addressed this condition by analysis.

The staff further determined that, assuming complete loss of concrete strength in this localized area, the steel liner alone is capable of resisting the design accident pressure, although no credit is taken for it in the containment design. In addition, the capacity of the containment structure to resist seismic loading would be unaffected because the maximum seismic loads occur at the base of the containment structure and are minimum at the top.

Therefore, the staff concluded that the applicant’s further evaluation of the elevated temperature condition at the upper elevation of containment is acceptable.

The staff noted that the applicant does not address penetrations through the containment and reactor building concrete for the main steam and feedwater lines in LRA Section 3.5.2.2.1.3. The concrete surrounding these penetrations needs to be maintained below 200EF during normal operation to prevent long-term degradation. The staff requested that the applicant provide its AMR results for the concrete surrounding these and any other penetrations for hot piping; and, if insulation and/or a penetration cooling system is credited for maintaining acceptable temperatures, to provide the AMR results for these items.

The applicant stated that the concrete surrounding the subject penetrations is addressed under "Concrete above grade" in LRA table 3.5.2-1. The specific aging effect associated with elevated temperature is addressed by GALL item number II.B2.2.1-g, within the "Concrete above grade" group. The commodity "Insulation," within Table 3.5.2-1 is credited with maintaining the penetration temperatures below the local limits of 200EF.

In its response, the applicant further stated that hot penetration temperatures, recorded on chart paper, were reviewed back to 1997. No penetration temperatures exceeded 200EF, with the highest recorded temperature of 185EF occurring between June 2003 and August 2003 on one of the main steam lines. As such, the insulation has proven effective in maintaining hot penetration temperatures below 200EF.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.3 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Loss of Material Due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate</u>. The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria found in SRP-LR Section 3.5.2.2.1.4:

> Loss of material due to corrosion could occur in inaccessible areas of the steel containment shell or the steel liner plate for all types of PWR and BWR containments. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

In LRA Section 3.5.2.2.1.4, the applicant stated that loss of material due to corrosion in inaccessible areas (embedded containment steel shell or liner) is not significant because of the following:

- The primary containment concrete structure was designed to ACI 318 and was constructed in accordance with ACI 301. The low water-cement ratio and air entrainment between 3 and 6 percent provides a dense concrete with low permeability, which meets the intent of ACI 201.2R.
- The concrete is monitored by the Structures Monitoring Program to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment liner.
- The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with IWE requirements.

- The above moisture barrier at the drywell liner and concrete containment floor interface has been designed to direct water away from the drywell liner. The containment concrete floor is sloped away from the drywell liner for drainage purposes. Periodic inspections of the concrete floor surface condition performed in accordance with the Structures Monitoring Program will validate the continued absence of corrosion for the inaccessible portions of the drywell liner.

During the audit, the staff determined that the applicant satisfied the specific criteria defined in the GALL Report for preventing loss of material due to corrosion in inaccessible areas of the steel liner; however, the applicant did not address plant-specific operating experience in LRA Section 3.5.2.2.1.41. The staff requested that the applicant provide details of the plant-specific operating experience for this aging effect/mechanism. If loss of material due to corrosion has occurred, the staff asked the applicant to describe the corrective actions taken to prevent future occurrences, to describe any augmented inspection of the concrete floor and/or the moisture barrier that is currently conducted (e.g., inspection every outage), and to describe any augmented inspection that is credited for the period of extended operation.

In its response, the applicant stated that degradation of the drywell liner, at the intersection of the concrete floor and moisture barrier, was identified in 1993. The degradation was extensively evaluated and weld repairs were performed in several areas. To minimize recurring corrosion, this area of the liner was re-coated with an epoxy coating and an enhanced moisture seal was installed in the expansion joint between the liner plate and the concrete floor that redirects any water in the vicinity away from the liner. Since the revised moisture barrier has been installed, no liner degradation has been identified; minor separation of the moisture barrier to the liner has been identified and repaired.

The applicant further stated that the moisture barriers are inspected once each inspection period (i.e., three examinations in a ten-year period) via a general visual examination. The IWE inspection for the moisture barrier lists the following recordable conditions: wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity; and moisture barrier separation at the interface to the liner and/or concrete. Specific instructions under acceptance criteria state: “Any condition that will permit intrusion of moisture against the inaccessible areas of the pressure-retaining surfaces of the metallic liner shall be repaired or replaced.” Inspection of the moisture barrier will be continued within the IWE program during the period of extended operation.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.4 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. In LRA Section 3.5.2.2.1.5, the applicant stated that the BSEP primary containment structure is constructed of reinforced concrete. There are no prestressed tendons associated with the primary containment structure design. Therefore, the aging effect, loss of prestress, is not applicable to the BSEP primary containment structure.

Cumulative Fatigue Damage. Cumulative fatigue is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed by staff in SER Section 4.3.

Cracking Due to Cyclic Loading and SCC. The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria found in SRP-LR Section 3.5.2.2.1.7:

> Cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC could occur in all types of PWR and BWR containments. Cracking could also occur in vent line bellows, vent headers and downcomers due to SCC for BWR containments. A visual VT-3 examination would not detect such cracks. The GALL Report recommends further evaluation of the inspection methods implemented to detect these aging effects.

In LRA Section 3.5.2.2.1.7, the applicant stated that the GALL Report discussion involves cracking due to cyclic loading and SCC of carbon steel, stainless steel, and dissimilar metal welds in containment penetration sleeves and bellows; and vent line bellows, vent headers, and downcomers. BSEP penetrations do not use expansion bellows, and penetration sleeves are fabricated from carbon steel. However, some penetrations incorporate stainless steel components, which require dissimilar metal welds. The vent line bellows are fabricated from stainless steel, and the vent header and downcomers are fabricated from carbon steel.

The applicant further stated that SCC is not an applicable aging effect for these components, because (1) carbon steel components are not susceptible to SCC, and (2) to be susceptible to SCC, stainless steel must be subject to both high temperature (>140 EF) and an aggressive chemical environment. Components fabricated from stainless steel are not subject to an aggressive chemical environment.

The applicant further stated that cracking of metal components owing to cyclic loads is a potential aging effect. However, the AMR, as supported by operating experience, concluded that cyclic loading from plant heatups and cooldowns, containment testing, and system vibration was very low or limited in numbers of cycles; therefore, additional methods of detecting postulated cracking were not warranted. The applicant also noted that the cyclic loading of the vent header and downcomers has been analyzed as a TLAA, and addressed in LRA Subsection 3.5.2.2.1.6.

The applicant further stated that, for the steel elements of containment that are part of the IWE pressure boundary; both the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program are used to monitor for degradation. However, the vent line bellows are inaccessible, and only the accessible surface areas of the assembly are subject to visual examination. A review of BSEP operating experience indicates that cracking has not been a concern for steel containment pressure boundary components.

The applicant concluded that, based on the above discussion, potential cracking of steel containment components is not expected, and use of the combination of the ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J Program, as recommended by the GALL Report, will adequately assure the detection of cracking should it occur.

The staff agreed with the applicant's further evaluation, with one exception. The staff noted that specific Mark I bellows design(s) have experienced cracking, and that the cracking was not detected by Appendix J leak rate testing. The staff requested the applicant to describe the bellows design, compared to the design(s) that developed cracks that were undetectable by Appendix J leak rate testing; and provide the technical basis for the determination that Appendix J leak rate testing would be able to detect cracks in the inaccessible regions of the vent line bellows.

The applicant stated that the bellows degradation referenced for another plant in their SER (NUREG-1796) was identified while conducting Appendix J testing and was associated with a 2-ply bellows. The subject bellows were replaced with a single-ply bellows. The Brunswick Containment Inspection Program (OBNP-TR-002) addresses the vent line bellows within Appendix F, augmented areas, as follows:

> Occurrences with transgranular stress corrosion cracking (TGSCC) with two-ply containment bellows were also identified. The containment design at BNP employs a single-ply containment bellows. These containment bellows are located inside the Suppression Chamber and are insulated by a protective cover. Unlike the examples given in SECY-96-080, a failure caused by transgranular stress corrosion cracking of these bellows is minimal. The controlled atmosphere, the protective cover over the bellows, and the location of these bellows inside the Suppression Chamber does not provide the environment (e.g., high temperature, surfaces exposed to a chemical environment, etc.) which is known to initiate stress corrosion cracking. In addition, no leakage associated with these bellows has been identified during previous Type A tests. Thus, this type of degradation at BNP is not a concern.

The staff acknowledges that the applicant is correct in that the other plant's bellows cracking was detected by Appendix J testing. BSEP employs a single-ply containment bellows design. The environment is not conducive to SCC, and previous Appendix J, Type A tests have not identified any leakage associated with the bellows. On this basis, the staff concluded that Appendix J, Type A leak rate testing is sufficient to manage cracking in the inaccessible regions of vent line bellows, and determined that the applicant's further evaluation is acceptable.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.7 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Class 1 Structures

Aging of Structures Not Covered by Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria found in SRP-LR Section 3.5.2.2.2.1:

> The GALL Report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1-3, 5, 7-9 structures; (2) scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1-5, 7-9 structures; (3) expansion and cracking due to reaction with aggregates for Groups 1-5, 7-9 structures; (4) cracking, spalling, loss of bond, and

loss of material due to corrosion of embedded steel for Groups 1-5, 7-9 structures; (5) cracks, distortion, and increase in component stress level due to settlement for Groups 1-3, 5, 7-9 structures; (6) reduction of foundation strength due to erosion of porous concrete subfoundation for Groups 1-3, 5-9 structures; (7) loss of material due to corrosion of structural steel components for Groups 1-5, 7-8 structures; (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1-5; and (9) crack initiation and growth due to SCC and loss of material due to crevice corrosion of stainless steel liner for Groups 7 and 8 structures. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program. Technical details of the aging management issue are presented in SRP-LR Subsection 3.5.2.2.1.2 for items (5) and (6) and Subsection 3.5.2.2.1.3 for item (8).

In LRA Section 3.5.2.2.2.1, the applicant stated that aging effects associated with freeze/thaw; leaching of calcium hydroxide; reaction with aggregates; corrosion of embedded steel; and aggressive chemical attack of concrete are not applicable, as discussed in the plant-specific notes associated with LRA Tables 3.5.2-1 through 3.5.2-15. Nevertheless, the Structures Monitoring Program is credited for aging management of these effects/ mechanisms for the affected structures, in accordance with the current NRC position (ISG-03). Corrosion of structural steel components is addressed by the Structures Monitoring Program.

The applicant further stated that aging effects associated with GALL Report, Volume 2, item III.A4.2-b, involve Lubrite slide-bearing plates. The plates provide a low-friction barrier between the equipment and their support structures. A review of industry operating experience, and 20 years of service at BSEP, reveals no adverse experience data recorded for the Lubrite sliding surfaces for applications both inside and outside containment. Based on the low cycle service required, it was concluded the Lubrite bearing plates will continue to perform their intended function for the period of extended operation.

During the audit, the staff also requested the applicant to describe any inspections of Lubrite plates that are currently conducted under the IWF, Maintenance Rule, or any other existing program; whether these inspections will continue during the extended period of operation; and whether they are credited for license renewal aging management.

In its response, the applicant stated that, as addressed by previous applicants and agreed with by the staff, Lubrite resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, tolerates high intensities of radiation, and will not score or mar. In addition, Lubrite products are solid, permanent, completely self-lubricating, and require no maintenance, as documented in NUREG-1759, “Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4.” A search of industry operating experience found no reported instances of Lubrite plate degradation or failure to perform its intended function, and, after more than 20 years of service, there has been no adverse experience data recorded for Brunswick Lubrite plates. Therefore, it is concluded that Brunswick Lubrite plates will not require aging management to perform their intended functions for the period of extended operation.

The applicant further stated that there is no inspection criteria specific to Lubrite in either the IWF or Maintenance Rule inspection programs. The IWF and Maintenance Rule programs monitor components within their scope for corrosion, deformation, cracks, and damage, etc.; as such, any visual degradation of the component associated with Lubrite would be identified and evaluated. The IWF program is credited for license renewal and will be continued during the period of extended operation. Maintenance Rule inspections will be continued during the period of extended operation. The Structures Monitoring Program, which utilizes the same inspection procedure credited by Maintenance Rule, is credited for license renewal aging management during the period of extended operation for non-IWF supports.

The staff determined the applicant's further evaluation for Lubrite plates to be acceptable, on the basis that there is no industry or plant-specific history of degradation, and on the basis that the AMPs credited by BSEP for inspection of component supports would identify and evaluate any visual degradation of Lubrite, should it occur.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.1 for further evaluation. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas. The staff reviewed LRA Section 3.5.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2. LRA Section 3.5.2.2.2.2 states:

> Cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack, and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas. The GALL Report recommends further evaluation to manage these aging effects in inaccessible areas of Groups 1-3, 5, 7-9 structures, if specific criteria defined in the GALL Report cannot be satisfied.

In LRA Section 3.5.2.2.2.2, the applicant stated that the service water intake structure is the only structure with concrete elements subject to aggressive ground water. The structure is located adjacent to the intake canal; therefore, the environmental parameters of the intake water have been applied to the below-grade portions of the concrete. Groundwater monitoring is performed periodically to validate that the below-grade environment is not aggressive for in-scope structures other than the service water intake structure. Examination of representative samples of below-grade concrete, when excavated for any reason, will be included as part of the Structures Monitoring Program, which will be used to manage aging due to aggressive chemical attack and corrosion of embedded steel.

In its review of the applicant's Structures Monitoring Program, as documented in SER Section 3.0.3.2.17, the staff confirmed that the Structures Monitoring Program includes periodic inspection of the submerged portions of the service water intake structure; periodic groundwater monitoring to validate that the below-grade environment is not aggressive; and examination of representative samples of below-grade concrete when excavated for any reason. For below-grade, inaccessible concrete areas, the applicant meets the specific criteria recommended in the GALL Report. For the service water intake structure, the applicant has defined an aging management program that is consistent with the recommendations of GALL AMP XI.S7, "Inspection of Water Control Structures," and included it as part of the Structures Monitoring Program.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.3 Component Supports

Aging of Supports Not Covered by Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.3.1 against the criteria in SRP-LR Section 3.5.2.2.3.1, which states:

> The GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports; (2) loss of material due to environmental corrosion, for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

In LRA Section 3.5.2.2.3.1, the applicant stated that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the Structures Monitoring Program. Degradation of these components/commodities at BSEP is managed by the Structures Monitoring Program.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.5.2.2.3 for further evaluation. The staff found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cumulative Fatigue Damage Due to Cyclic Loading. Cumulative fatigue is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in SER Section 4.3.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant adequately addressed the issues that were further evaluated. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.5.2-1 through 3.5.2-15, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.5.2-1 through 3.5.2-15, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report, and it provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line-item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line-item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line-item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line-item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.5.2.3.1 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Primary Containment – Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, which summarizes the results of AMR evaluations for the primary containment component groups.

Summary of Technical Information in the Application. In LRA Section 3.5.2.1.1, the applicant identified materials, environment, and AERMs. The applicant identified the following programs that manage the AERMs for the primary containment structures components:

- Structures Monitoring Program
- ASME Section XI Subsection IWE Program
- ASME Section XI Subsection IWL Program
- ASME Section XI Subsection IWF Program
- 10 CFR 50 Appendix J Program

In LRA Table 3.5.2-1, the applicant provided a summary of AMRs for the Primary Containment Structures components and identified which AMRs it considered to be consistent with the GALL Report. In LRA Table 3.5.2.-1, the applicant provided a summary of AMR results for primary containments.

Staff Evaluation. The staff's review of LRA Section 3.5 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAIs as discussed below.

In RAI 3.5-1, dated April 8, 2005, the staff stated that the refueling bellows are manufactured from stainless steel, and they are protected from weather. The components protected from weather are not necessarily immune to loss of material. As the bellows are located between the refueling cavity and the drywell, they come in direct contact with water, and subjected to sustained moist condition. In similar situations, the stainless steel bellows of some ice-condenser and Mark 1 containments (see IN 92-20) have experienced degradation and cracking. Therefore, the staff requested that the applicant provide justification for not managing the aging of the bellows during the period of extended operation.

In its response, by letter dated May 4, 2005, the applicant stated that the refueling bellows are not containment pressure boundary components and are not subject to the frequency and severity of loading as would be experienced by containment pressure boundary penetration bellows described in IN 92-20, "Inadequate Local Leak Rate Testing." The refueling bellows provide an expansion boundary between the exterior drywell wall and the reactor building, inside the refueling cavity. The primary environment seen by the refueling bellows is warm, dry air, with short periods of immersion in demineralized water when the reactor refueling cavity is flooded. Following refueling, any residual demineralized water would evaporate quickly. The long-term environment, for material aging purposes, is protected from weather, with reactor building air on both sides of the bellows. Based on the subject environment and consistent with industry guidance, the stainless steel is not subject to degradation.

The staff concern related to the leakage of refueling bellows in BWR Mark 1 containments is related to corrosion of steel drywell from the inaccessible area of the shell. A review of the detail of the drywell bellows indicates that, because the Brunswick drywell is of reinforced concrete construction, any leakage from bellows will not affect the drywell liner plate. Therefore, based on the applicant's response, the staff's concern described in RAI 3.5-1 is resolved.

In RAI 3.5-2, dated April 8, 2005, the staff stated that the cable trays and conduits are either made of galvanized carbon steel, or stainless steel. The staff further noted that the potential for corrosion of stainless steel cable trays/conduits is remote, unless they are subjected to sustained high temperatures (> 140 EF) and the material yield strength is high (> 140 ksi). Loss of material due to galvanic corrosion is more likely for the cable trays/conduits if they are subjected to a humid environment and welded to non-galvanized carbon steel supports. Therefore, the staff requested that the applicant discuss why the BSEP cable trays and conduits and all components/commodities with Notes 521 and 529 from LRA Tables 3.5.2-1 through 3.5.2-15 need no aging management. As part of the justification, the applicant was requested to provide operating experience related to these components/commodities.

In its response, dated May 4, 2005, the applicant explained that only the upper elevations of the drywell are subject to temperatures between 140 EF and 200 EF, and no degradation of galvanized or stainless steel components have been identified within plant operating experience in this area. Based on industry guidance, loss of material by general corrosion is not an applicable aging effect for galvanized steel exposed to, or protected, from weather; unless the pH of precipitation is outside the range of 6 to 12, or temperatures are between 140 EF and 200 EF. Also, based on industry guidance, galvanized steel is not subject to galvanic corrosion because the zinc coating provides galvanic protection of the carbon steel base metal even under degraded conditions. Therefore, loss of material by galvanic corrosion is not an applicable aging effect for galvanized steel protected from or exposed to weather. Precipitation is not monitored at BSEP; however, groundwater is monitored for pH and the results show the pH is not outside the range of 6 to 12. Plant operating experience has not identified degradation of galvanized or stainless steel components where the ambient environment is not aggressive, which is consistent with the industry guidance discussed above. Based on review of typical cable tray and conduit support details and discussions with system and welding engineers, BSEP does not weld cable trays or conduits to non-galvanized carbon steel supports. Cable tray and conduit supports are typically fabricated from galvanized unistrut members and fittings. Furthermore, the applicant stated that

BSEP has identified loss of material as an applicable aging effect for cable trays and conduits and all galvanized and stainless in-scope civil components in the service water intake structure, based on the aggressive environment in that location and plant operating experience. See LRA plant-specific Note 544 for further information.

The applicant performed an AMR based on plant-specific and industry experience related to the cable trays and conduits made of galvanized carbon steel and stainless steel. The staff review of Note 544 indicated that the applicant appropriately designated aging management of cable trays and conduits made of galvanized carbon steel and stainless steel in the service water intake structure, where the environment has been found to degrade these components. Therefore, the staff found the applicant's approach in performing the AMR of these components adequate and acceptable. Therefore, the staff's concern described in RAI 3.5-2 is resolved.

In RAI 3.5-3, dated April 8, 2005, the staff stated that in context with GALL Report item II.B2.2.21-g, related to the concrete components subjected to elevated temperatures, the applicant provided an evaluation in Note 536 and in LRA Section 3.5.2.2.1.3. The staff did not agree with the applicant's interpretation that the upper portion of the drywell subjected to sustained temperatures of approximately 170EF can be considered as "local area." However, the staff indicated that on a case-by-case basis, the staff has approved such temperatures without complex analysis, provided the concrete components and the load-bearing items attached to such concrete components are periodically monitored. In light of the above discussion. Therefore, the staff requested that the applicant justify why the items in LRA Table 3.5.2-1 with Notes 536 and 513 should not be subjected to aging management during the period of extended operation.

In its response dated May 4, 2005, the applicant explained that Note 536 is applicable to the containment pressure boundary concrete, and Note 513 is applicable to containment internal concrete and concrete outside the containment. The only BSEP concrete above the 150EF temperature level is associated with the upper elevations of the containment pressure boundary concrete, as stated in Note 536. The containment pressure boundary concrete is subjected to aging management by both the ASME Section XI, Subsection IWL Program and the Structures Monitoring Program; as such, the concrete components are periodically monitored.

The staff found the applicant's response acceptable, as the applicant will manage the aging of concrete components inside the containment by its Structures Monitoring Program, and the primary containment reinforced concrete outside areas by ASME Code Section XI, Subsection IWL during the period of extended operation.

In RAI 3.5-4, dated April 8, 2005, the staff noted that based on the evaluation provided in LRA Section 3.5.2.2.1.3, a number of load resisting reinforced concrete structures within the drywell shell would likely be subjected to temperatures higher than the established threshold of 150EF. The staff requested the applicant to provide a summary of the operating experience related to the reliability of the cooling ventilation system, if these structures were kept within the threshold temperature of 150EF by a cooling system. Therefore, the staff requested that the applicant provide a summary of the results of the last inspections performed on (1) RPV pedestal supports, (2) the foundation and floor slabs, and (3) the sacrificial shield wall under the existing Structures Monitoring Program.

In its response, by letter dated May 4, 2005, the applicant stated that the containment bulk average temperature is managed under TS 3.6.1.4, which requires the plant enter LCO actions if the drywell temperature exceeds 150 EF. In response to the subsequent request, the applicant stated that the last two inspections performed under the existing Structures Monitoring Program, dated March 15, 2004, for Unit 1 and February 25, 2001, for Unit 2, identified no degradation associated with the RPV pedestal supports, the floor slabs, or the sacrificial shield wall. The only issues identified were coating deficiencies, which were referred to the Coating Inspection Program, and an improperly supported grating.

The staff believes that maintaining the bulk temperature in the containment, as required by TS 3.6.1.4, will ensure that the concrete material properties; that is, compressive strength and modulus of elasticity, will not be significantly affected. Even within the TS-established bulk temperature, cracking and spalling of concrete cannot be ruled out. The applicant will be inspecting these areas under its Structures Monitoring Program. Therefore, the staff's concern described in RAI 3.5-4 is resolved.

In RAI 3.5-5, dated April 8, 2005, the staff stated that item hot penetration insulation, in Table 3.5.2-1, has been screened out as having no aging effects, and did not require aging management (Note 540). As the inside sustained temperature of the containment is high (>140 EF), and the outside is subjected to the reactor building temperature, the concrete temperatures around these penetration is likely to be high. Therefore, the staff requested that the applicant discuss the plant-specific operating experience related to the effectiveness of the insulation in keeping the temperatures around these penetrations (in the containment concrete) below 200 EF.

In its response, by letter dated May 4, 2005, the applicant stated that hot penetration temperatures, recorded on chart paper, were reviewed back to 1997. No penetration temperatures exceeded 200 EF, with the highest recorded temperature of 185 EF occurring between June 2003, and August 2003, on one of the main steam lines. From these observations, the applicant infers that the insulation has proven effective in maintaining hot penetration temperatures below 200 EF.

In follow-up to RAI 3.5-5, the staff reiterated the following concern: As the insulation around hot penetrations could be affected by time-dependant aging, and the applicant does not plan to monitor its effectiveness, the applicant was requested to provide a schedule for monitoring the penetration or concrete temperature during the period of extended operation, as was done prior to submitting the LRA. In its supplemental response, by dated August 11, 2005, the applicant noted that the penetration insulation material is fabricated from hydrous calcium silicate, and added that, although not a requirement of the Structures Monitoring Program, hot penetration temperatures are periodically monitored by the primary containment system engineer and trended in the system notebook. The staff found the applicant's method of monitoring hot penetration temperatures adequate and acceptable, as it will signal significant departures from the threshold temperature, and prompt the applicant to take necessary actions. Therefore, the staff's concern described in the supplemental response to RAI 3.5-5 is resolved.

In RAI 3.5-6, dated April 8, 2005, the staff agreed with the applicant that in general, the sump stainless steel liner is not subject to aging management, so far as it meets the threshold criteria for stainless steel discussed in RAI 3.5-2. However, the staff observed that the thin sump liner needs to have some type of periodic inspection to assure that it has not bulged excessively between the anchors, and was not affected by the dissimilar weld details at penetrations and at the junctions of carbon steel components. Therefore, the staff requested that the applicant discuss the plant-specific as well as the industry experience related to the condition of the stainless steel sump liners, and to justify the AMR conclusion that no aging management is needed for stainless steel sump liners.

In its response, by letter dated May 4, 2005, the applicant emphasized that the subject sump is fabricated entirely of stainless steel; all attached piping is fabricated from stainless steel; and it does not contain any dissimilar welds. The sump is a very high radiation environment; as such, it is treated as an inaccessible area. The sump pump was modified in 2000 by replacing the submersible pump with a top-mount motor and cantilevered pump. No degradation was recorded during installation; however, the water level within the sump was maintained as high as possible for shielding purposes. Any observable degradation identified during periodic maintenance of the pumps, performed every refueling outage, will be evaluated through the normal work process. Furthermore, the applicant explained that the liner is considered inaccessible, and any degradation identified for similar stainless steel liners would be considered applicable to the sump liner and an evaluation performed in accordance with the BSEP corrective action process.

The staff considered the approach taken by the applicant in assessing the condition of the sump liner in this high-radiation area acceptable, as the industry-wide experience, in general, indicates that the stainless steel sump liner is not subjected to systematic degradation.

In RAI 3.5-7, dated April 8, 2005, the staff stated its concern regarding the different write-ups in LRA Table 3.5.2-1, item 3.5.1-02, and in component “penetrations” related to aging management of penetrations (including sleeves and bellows). In item 3.5.1-02, the applicant has credited the ASME XI, IWE, and 10 CFR 50, Appendix J Programs for aging management, and provided acceptable further evaluation in LRA Section 3.5.2.2.1.7. However, in LRA Table 3.5.2-1, the applicant asserted “no aging effects,” and “no AMP.” Note 542 reiterates the AMPs stated in item 3.5.1-02. Therefore, the staff requested that the applicant clarify this contradictory LRA requirements.

In its response, by letter dated May 4, 2005, the applicant indicated that the further evaluation information in LRA Section 3.5.2.2.1.7 addressed cracking in both items 3.5.1-02 and 3.5.1-17 components. Item 3.5.1-02 covers penetration sleeves, bellows, and dissimilar metal welds. Item 3.5.1-17 addresses steel elements; vent line bellows, vent headers, and downcomers. Therefore, LRA Section 3.5.2.2.1.7 is written to address all of the above components. With respect to the penetration components (i.e., 3.5.1-02), the aging management review determined that they had no aging effects involving cracking. For those line items on Table 3.5.2-1, generic Note I was used, and GALL Report, Volume 2 was referenced to indicate what specific aging effect was not applicable. The ASME Section XI, Subsection IWE and 10 CFR 50 Appendix J Programs are credited for steel components that form the pressure boundary of primary containment. Therefore, plant-specific Note 541 was used.

The staff found the applicant’s clarification acceptable, as it succinctly separated the items such as penetration sleeves, bellows, and dissimilar metal welds, and vent line bellows, vent headers and downcomers. Therefore, the staff’s concern described in RAI 3.5-8 is resolved.

In RAI 3.5-8, dated April 8, 2005, the staff stated its concern and skepticism regarding the industry position that, without providing acceptable technical justification, no aging management of Lubrite bearings is needed. Some of the aging effects/mechanism could be loss of mechanical function because of distortion, dirt accumulation, fatigue due to vibratory and cyclic thermal loads, and gradual degradation of the lubricant used, particularly, when subjected to sustained elevated temperatures and radiation (inside containment). The staff further noted that without systematic investigation of these factors, it would be difficult to accept a position that “no aging management of Lubrite bearings is needed (Note 524). Therefore, in the context of the above discussion, the staff requested that the applicant provide information that would justify that none of the conditions cited in the aging effects/mechanism above is possible where the Lubrite plates are used in BSEP.

In its response, by letter dated May 4, 2005, the applicant stated that as addressed by previous applicants, Lubrite resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, tolerates high intensities of radiation, and will not score or mar. In addition, Lubrite products are solid, permanent, completely self-lubricating, and require no maintenance. As documented in NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4," NRC staff has agreed that there are no known aging effects for Lubrite. A search of industry operating experience found no reported instances of Lubrite plates degrading or failing to perform their intended function; and, after more than 20 years of service, there has been no adverse experience data recorded for BSEP Lubrite plates. Lubrite plates at BSEP are typically located in a closed, clean environment, such as the drywell or reactor building, and are not subject to accumulation of dirt or debris. It is therefore concluded that the Lubrite plates will not require aging management to perform their intended functions for the period of extended operation.

In its supplemental response to RAI 3.5-8, by letter dated June 14, 2005, the applicant stated that the ASME Section XI, Subsection IWF and Structures Monitoring Program did not specifically address Lubrite; however, the inspection criteria for supports within the programs effectively enveloped misalignment and accumulation of debris.

The staff found that the applicant’s position, that aging management of Lubrite supports are included as part of the examinations of ASME supports under its IWF program, and non-ASME supports are under its Structures Monitoring Program, is acceptable. Therefore, the staff’s concern described in RAI 3.5-8 is resolved.

In RAI 3.5-9, dated April 8, 2005, the staff stated that in the LRA, the applicant did not specify the AERM or AMP for the embedded/encased carbon steel (LRA Tables 3.5.2-1, 3.5.2-4, and 3.5.2-7 through 3.5.2-15) and galvanized carbon steel (LRA Table 3.5.2-4) anchorages/embedments. In plant-specific Notes 518 and 519 for Tables 3.5.2-1 through 3,5,2-15, the applicant stated that the BSEP AMR methodology concluded that carbon/low-alloy steel and galvanized carbon/low-alloy steel, completely encased in concrete, are not subject to aging effects. The staff’s concern is that the carbon/low-alloy steel and galvanized carbon/low-alloy steel are likely subject to corrosion and loss of material for conditions involving cracked concrete. Therefore, the staff requested that the applicant provide its justification for not considering aging effects for these structural elements.

In its response, by letter dated May 4, 2005, the applicant stated that the AMR results documented in the LRA (reflected in plant-specific Notes 518 and 519) involve steel components that are completely encased in concrete so that the protection from corrosion afforded by the highly alkaline environment is present. Therefore, no aging management is needed. For the case of cracked concrete, the applicant agreed with the staff that plant-specific Notes 518 and 519 are not applicable. The applicant further stated, in its response, that the condition of concrete in BSEP structures within the scope of license renewal will be monitored by the ASME Section XI, IWL and Structures Monitoring Programs that would detect the presence of cracking in the vicinity of embedded steel components. On the basis of the above discussion, the staff considered the applicant's response acceptable; therefore, RAI 3.5-9 is resolved.

In RAI 3.5-11, dated April 8, 2005, the staff stated that LRA Section 3.5.2.2.2.1, "Aging of Structures Not Covered by Structures Monitoring Program," states that aging effects associated with aggressive chemical attack on concrete, etc. are not applicable as discussed in the plant-specific notes associated with LRA Tables 3.5.2-1 through 3.5.2.15. In LRA Tables 3.5.2.2 through 3.5.2-15, the applicant, based on the plant-specific Notes 501 and 517, did not specify the AERM for Class I below-grade concrete structures (reactor building, augmented off-gas building, diesel generator building, control building, turbine building, radwaste building, and miscellaneous structures and out buildings). Note 501 states that although no aging effects have been identified, the specified GALL Report program will be assigned for management of this commodity, in accordance with the NRC's current position (ISG-03); and Note 517 states that groundwater monitoring is performed periodically to validate the assumption that the groundwater below-grade environment is not aggressive. In LRA Section 3.5.2.2.2.2, "Aging Management of Inaccessible Areas," the applicant stated that the service water intake structure is the only structure with concrete elements subject to aggressive groundwater. The structure is located adjacent to the intake canal; therefore, the environmental parameters of intake water have been applied to the below-grade portions of the concrete. Therefore, the staff requested that the applicant provide additional information to explain how the water chemistry is monitored, including past and current groundwater qualities (pH values and content of chlorides and sulfates), frequency of monitoring, specific monitoring program used, and future plan for groundwater monitoring.

In its response, by letter dated May 4, 2005, the applicant stated that the groundwater is currently being monitored by the implementing procedure 0E&RC-3250, Groundwater Monitoring Program, and the monitoring will be continued during the period of extended operation. The results of groundwater monitoring in the years of 2002 and 2004, as shown in the table below, indicate that pH values and content of chlorides and sulfates are below the GALL Report limits for aggressive groundwater (pH< 5.5, chloride > 500 p.m. and sulfate >1500 p.m).

Parameter	GALL Criteria for Aggressive Environment	Well# ESS-1B		Well# ESS-2B		Well# ESS-3B		Well# ESS-13C		Manhole 2-MH-CB7	
		Date		Date		Date		Date		Date	
Year		**02**	**04**	**02**	**04**	**02**	**04**	**02**	**04**	**02**	**04**
pH	< 5.5	7.5	7.0	6.6	6.9	7.0	7.2	6.6	6.7	N/A	6.4
Chlorides	> 500 p.m.	36	26	49	31	27	12	34	21	N/A	11
Sulfate	>1500 p.m.	2	<5	66	48	50	10	18	<5	N/A	45

The applicant also stated that a one-time inspection was performed on Well No. ESS-3B for phosphate, and the result indicates that the groundwater phosphate level is at 0.12 ppm. In addition, the applicant stated that an enhancement to the Structures Monitoring Program implementing procedure EAR-NGGC-0351, "Condition Monitoring of Structures," will be performed prior to the period of extended operation that requires the structures system engineer to review the groundwater monitoring results against the applicable parameters for an aggressive below-grade environment. On the basis of the above discussion, the staff considers the applicant's response acceptable, except that the applicant did not specify the frequency of the future groundwater monitoring as requested in the RAI.

A review of the applicant's response to audit item AQ B.2.23-2, attached to its letter (BSEP-05-0041) dated March 14. 2005, indicates that the applicant plans to enhance its Structures Monitoring Program to specify an annual groundwater monitoring frequency for concrete structures. The staff found the frequency of ground water monitoring adequate and acceptable; therefore, RAI 3.5-11 is resolved.

3.5.2.3.2 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Intake and Discharge Canals – Table 3.5.2-2.

As described in SER Section 3.5.2.1, the staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the intake and discharge canals and no RAI was identified.

3.5.2.3.3 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Refueling System – Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the refueling system component groups.

The applicant plans to manage the aging of the line items fuel prep machines and auxiliary work platforms under its Structures Monitoring Program, and the staff found the applicant's aging management review of these items acceptable.

3.5.2.3.4 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Switchyard and Transformer Yard Structures – Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for the switchyard and transformer yard structures component groups.

In RAI 3.5-10, dated April 8, 2005, the staff stated that in LRA Table 3.5.2-4, the applicant did not specify the AERM or AMP for the carbon steel piles that were driven in undisturbed soil. In Note 522 of LRA Table 3.5.2-4, the applicant stated that, based on NUREG-1557, steel piles driven in undisturbed soils have been unaffected by corrosion; and those driven in disturbed soil experience minor to moderate corrosion to a small area of metal. Therefore, no aging effects have been concluded for steel piles. However, it is the staff's understanding that the conclusion of NUREG-1557 (References 16 and 17 of the LRA) is based on less than 40-year data. There are other industry documents and design manuals which indicate that significant corrosion of steel piles has been identified, even when piles were driven in undisturbed soil. Therefore, the staff requested that the applicant provide additional information to justify the validity of its conclusion.

In its response, by letter dated May 4, 2005, the applicant stated, by referencing EPRI TR-103842, "Class I Structures License Renewal Industry Report," that in addition to the conclusion drawn in NUREG-1557, a study by Romanoff involved 43 steel piles driven to depths up to 136 feet into a wide variety of soil conditions. The time of exposure of this study varies from 7 to 50 years. The data indicate that the type and amount of corrosion observed on steel pilings driven into undisturbed natural soil, regardless of the soil characteristics and properties, is not sufficient to significantly affect the strength of pilings as load bearing structures. The data also indicate that undisturbed soils are so deficient in oxygen at levels a few feet below the ground surface or below the water table, that steel piles are not appreciably affected by corrosion, regardless of the soil type or the soil properties. Also, in its response to RAI 3.5-11 (discussed above) the applicant demonstrated that the water chemistry at the Brunswick site is not aggressive (pH, chlorides, and sulfates are within the limits of the GALL). On the basis of the above discussion, RAI 3.5-10 is resolved.

In addition to the line items anchorage/embedment, concrete below grade (which are discussed in SER Section 3.5.2.3.1), and carbon steel piping, the staff reviewed five line items (cable tray/conduit, electrical support, equipment support, siding, and structural steel) listed in this table, and found the applicant's AMR of these items acceptable.

3.5.2.3.7 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Service Water Intake Structure – Table 3.5.2-7

The staff reviewed LRA Table 3.5.2-7, which summarizes the results of AMR evaluations for the service water intake structure component groups.

Because of the harsh environment in the intake structure, except for the anchorage/embedments, the applicant plans to monitor the aging of concrete below grade, and another 14 line items (cable tray/conduit, concrete below grade, electrical enclosure, electrical support, equipment support, fire hose station, floor drains, instrument racks, instrument support, pipe support, roof-membrane/built-up, seals and gaskets, spray shield, and spray on coatings) under its Structures Monitoring Program. Therefore, the staff found the applicant's AMR acceptable.

3.5.2.3.8 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Reactor Building – Table 3.5.2-8

The staff reviewed LRA Table 3.5.2-8, which summarizes the results of AMR evaluations for the reactor building component groups.

In addition to the line items anchorage/embedment and concrete below grade (which are discussed in SER Section 3.5.2.3.11), the staff reviewed 21 line items such as, concrete curbs, damper mounting, electrical enclosure, electrical support, equipment support, fire barrier assembly, fire hose station, floor drains, HVAC support, instrument racks, instrument support, liner, pipe support, roof-membrane/built-up, seals and gaskets, siding, siding bearing plate, spent fuel storage rack, spray shield, spray on coatings, and tendons listed in the table, and found the applicant's aging management review of these items acceptable. The aging management of fuel pool girder tendons and the relevant TLAA for monitoring of prestressing force in the tendons are reviewed in SER Sections B.2.32, and 4,7.2.

3.5.2.3.9 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Augmented Off-Gas Building – Table 3.5.2-9

The staff reviewed LRA Table 3.5.2-9, which summarizes the results of AMR evaluations for the augmented off-gas building component groups.

In addition to the line items anchorage/embedment and concrete below grade (which are discussed in SER Section 3.5.2.3.1), the staff reviewed eight line items (cable tray/conduit, doors, electrical enclosure, electrical support, equipment support, fire hose station, penetrations, and siding bearing plate) listed in the table, and found the applicant's aging management review of these items acceptable.

3.5.2.3.10 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Diesel Generator Building – Table 3.5.2-10

The staff reviewed LRA Table 3.5.2-10, which summarizes the results of AMR evaluations for the diesel generator building component groups.

In addition to the line items anchorage/embedment and concrete below grade (which are discussed in SER Section 3.5.2.3.1), the staff reviewed 14 line items (blow-out panel, cable tray/conduit, concrete curbs, damper mounting, electrical enclosure, electrical support, fire barrier assembly, fire hose station, floor drains, pipe support, roof-built-up, siding, spray shield, and spray on coatings) listed in the table, and found the applicant's AMR of these items acceptable.

3.5.2.3.11 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Control Building – Table 3.5.2-11

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the control building component groups.

In addition to the line items anchorage/embedment and concrete below grade, (which are discussed in SER Section 3.5.2.3.1), the staff reviewed 12 line items (cable tray/conduit, concrete above grade, control room ceiling, damper mounting, electrical enclosure, electrical support, fire barrier assembly, fire hose station, raised floor, seals and gaskets, roof-membrane/built-up, and spray on coatings) listed in the table, and found the applicant's AMR of these items acceptable.

3.5.2.3.12 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Turbine Building – Table 3.5.2-12

The staff reviewed LRA Table 3.5.2-12, which summarizes the results of AMR evaluations for the turbine building component groups.

In addition to the line items anchorage/embedment and concrete below grade (which are discussed in SER Section 3.5.2.3.1), the staff reviewed nine line items (cable tray/conduit, concrete above grade, concrete curbs, electrical enclosure, electrical support, fire barrier assembly, fire hose station, roof-membrane/built-up, and siding) listed in the table, and found the applicant's AMR of these items acceptable.

3.5.2.3.13 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Radwaste Building – Table 3.5.2-13

The staff reviewed LRA Table 3.5.2-13, which summarizes the results of AMR evaluations for the radwaste building component groups.

In addition to the line items anchorage/embedment and concrete below grade (which are discussed in SER Section 3.5.2.3.1), the staff reviewed six line items (cable tray/conduit, concrete above grade, doors, electrical enclosure, fire hose station, and roof-membrane/built-up) listed in the table, and found the applicant's AMR of these items acceptable.

3.5.2.3.14 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Water Treatment Building – Table 3.5.2-14

The staff reviewed LRA Table 3.5.2-14, which summarizes the results of AMR evaluations for the water treatment building component groups.

In addition to the line items anchorage/embedment and concrete below grade (which are discussed in SER Section 3.5.2.3.1), the staff reviewed eight line items (cable tray/conduit, concrete above grade, electrical enclosure, battery rack, electrical support, fire barrier assembly, siding, and structural steel) listed in the table, and found the applicant's AMR of these items acceptable.

3.5.2.3.15 Containments, Structures, and Component Support – Summary of Aging Management Evaluation – Miscellaneous Structures and Out-Buildings – Table 3.5.2-15

The staff reviewed LRA Table 3.5.2-15, which summarizes the results of AMR evaluations for the miscellaneous structures and out-buildings component groups.

In addition to the line items anchorage/embedment, concrete below grade, and piles (which are discussed in SER Section 3.5.2.3.1), the staff reviewed eight line items (cable tray/conduit, concrete BWR vent stack, concrete above grade, tank foundation, electrical support, instrument support, siding, and structural steel) listed in the table, and found the applicant's AMR of these items acceptable.

3.5.2.3.16 Conclusion on Subsections 3.5.2.3.2 to 3.5.2.3.15

On the basis of its review, the staff found that the applicant appropriately evaluated AMR results involving material, environment, AERMS, and AMP combinations that are not evaluated in the GALL Report. The staff found that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging of the containments, structures, and component supports components, that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the containments, structures, and component supports, as required by 10 CFR 54.21(d).

3.6 Aging Management of Electrical and Instrumentation and Controls

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and instrumentation and control (I&C) components and component groups associated with the following systems:

- non-EQ insulated cables and connections
- phase bus
- non-EQ electrical/I&C penetration assemblies
- high voltage insulators
- switchyard bus
- transmission conductors

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant provided AMR results for electrical and I&C components. In LRA Table 3.6.1, "Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the electrical and I&C components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff performed an onsite audit of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the Audit and Review Report and are summarized in SER Section 3.6.2.1.

During the audit, the staff reviewed the AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.6.2.2. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.6.2.2.

During the audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating (1) whether all plausible aging effects were identified, and (2) whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the Audit and Review Report and are summarized in SER Section 3.6.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.6.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the electrical and I&C components.

Table 3.6-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.6, that are addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and Instrumentation and Controls in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements (Item 3.6.1-01)	Degradation due to various aging mechanisms	Environmental qualification of electric components	TLAA	This TLAA is evaluated in Section 4.4, Environmental Qualification of Electrical Equipment
Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements (Item 3.6.1-02)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure caused by thermal/ thermoxidative degradation of organics; radiolysis and photolysis [ultraviolet (UV) sensitive materials only] of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.25)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (IR) (Item 3.6.1-03)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging management program for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (B.2.26)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
Inaccessible medium-voltage (2 kV to 15 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (Item 3.6.1-04)	Formation of water trees; localized damage leading to electrical failure (breakdown of insulation); water tress caused by moisture intrusion	Aging management program for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (B.2.27)	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
Electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage (Item 3.6.1-05)	Corrosion of connector contact surfaces caused by intrusion of borated water	Boric acid corrosion		Not applicable, PWR only

The staff's review of the BSEP component groups followed one of several approaches. One approach, documented in SER Section 3.6.2.1, discusses the staff's review of the AMR results for components in the electrical and I&C component groups that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.6.2.2, discusses the staff's review of the AMR results for components in the electrical and I&C systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, discusses the staff's review of the AMR results for components in the electrical and I&C component groups that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the electrical and I&C components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the electrical and I&C components:

- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
- Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program
- Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
- Phase Bus Aging Management Program

<u>Staff Evaluation</u>. In LRA Table 3.6.2-1, the applicant provided a summary of AMRs for the electrical and I&C components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicate that the AMR is consistent with the GALL Report.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is different from, but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit of the information provided in the LRA, as documented in the Audit and Review Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation has been discussed in the Audit and Review Report.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the electrical components. The applicant stated that environmental qualification (EQ) is a TLAA, as defined in 10 CFR 54.3. Aging evaluations for EQ components that specify a qualified life of 40 years are considered to be TLAAs for license renewal.

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in Section 3.6.2.2 of the SRP-LR.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA separately in SER Section 4.4, following the guidance in SRP-LR Section 4.4.

3.6.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Table 3.6.2-1, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Table 3.6.2-1, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line-item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line-item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line-item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line-item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combination that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.6.2.3.1 Phase Bus

Phase bus is used to connect two or more elements (electrical equipment such as switchgear and transformers) of an electrical circuit. Isolated phase bus is an electrical bus in which each phase conductor is enclosed by an individual metal housing separated from adjacent conductor housing by an air space. Non-segregated phase bus is an electrical bus constructed with all phase conductors in a common enclosure without barriers (only air space) between the phases.
See SER Section 3.0.3.3.4 for staff evaluation for Phase Bus Aging Management Program (B.2.31).

On the basis of its review, the staff found that this is a non-GALL program and that this program provides adequate management of the aging effects of the bus ducts. The staff also reviewed the UFSAR supplement for this AMP and found that it provides an adequate summary description of the program as required by 10 CFR 54.21(d).

3.6.2.3.2 Non-EQ Electrical/I&C Penetration Assemblies

The applicant stated that many electrical/I&C assemblies are included in the EQ program and, therefore, do not meet the criteria of 10 CFR 54.21(a)(1) and are not subject to an AMR. A small number of non-EQ electrical/I&C penetration assemblies are subject to an AMR. The materials of construction for the non-EQ electrical/I&C penetration assemblies are:

- XLPE, cross-linked polyolefin (XLPO), and SR internal conductor/pigtail insulation
- Dow Corning 185 Encapsulant
- Ceramic

The non-EQ electrical/I&C penetration assemblies are exposed to heat, radiation, and oxygen.

Aging Effects. The applicant stated that the non-EQ electrical/I&C penetration assemblies subject to AMR are Westinghouse Class E or Class D2 assemblies. The penetration assembly primary insulation materials are XLPE, XLPO, and SR (insulation). The AMR of these materials identified no AERMs based on an analysis of 60-year service limiting environments for the penetration locations in the lower drywell. Also, an aging analysis of the direct current (DC) 185 encapsulant determined that the material is acceptable for BSEP during 60-year service life inside the lower drywell. Therefore, the non-EQ electrical/I&C penetration assemblies have no AERMs for the period of extended operation.

Aging Management Programs. The applicant determined that no aging management activities are required for the extended period of operation for the organic insulating and encapsulant materials within the penetration assemblies. Therefore, no AMPs are required for the non-EQ electrical/I&C penetration assemblies. However, as a conservative measure, potential aging effects of penetration pigtail wiring insulation will be addressed by the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program.

In LRA Section 3.6.2.1.3, the applicant stated that the penetration assembly primary insulation materials are XLPE, XLPO, and SR. The AMR of these materials identified no AERMs based on an analysis of 60-year service limiting environments for the penetration locations in the lower drywell. Also, an aging analysis of the DC 185 encapsulant determined that the material is acceptable for BSEP during 60-year service life inside the lower drywell.

In RAI 3.6.2.3-2, dated May 18, 2005, the staff requested that the applicant address why the metals and inorganic materials (such as cable fillers, epoxies, potting compounds, connector pins, plugs, and facial grommets) associated with non-EQ electrical/I&C penetration assemblies do not require an AMR.

In its response, by letter dated June 14, 2005, the applicant stated:

> Electrical penetration assemblies are used to pass electrical circuits through the containment drywell while maintaining drywell integrity. The intent of the electrical AMR of electrical penetration assemblies is to preserve the electrical continuity function of the penetration assemblies. The focus of this review is to evaluate the interaction between the organic insulating materials of the penetration assemblies and their operating environment. The organic insulating materials comprise the penetration primary insulation system of the assemblies. In addition to organic insulating materials, there are other materials (i.e., metals and inorganic materials) used in the construction of the penetration assembly. These include cable fillers, epoxies, potting compounds, connector pins, plugs, and facial grommets. Consistent with the findings from Department of Energy (DOE)/Sandia Aging Management Guideline (SAND 96-0344) these items have no significant effect on the normal aging process of the primary insulation system and do not adversely affect the electrical continuity function of the penetration assemblies. Therefore, no AMR of these materials is warranted. The civil/structural pressure boundary function of the penetration is tested by the Appendix J Program as shown in Table 3.5.2-1 of the LRA.

The staff found the applicant’s response acceptable because the potential aging effects of penetration wiring insulation will be addressed by the Electrical Cables and Connections Not

Subject to 10 CFR 50.49 EQ Requirements Program and the leak test as required by Appendix J Program will test the boundary function of the non-EQ electrical and I&C penetrations. Therefore, the staff's concern described in RAI 3.6.2.3-2 is resolved.

On the basis of its review, the staff concluded that the applicant adequately identified the aging effects, and has an adequate AMP for managing the aging effects for containment electrical penetrations, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.3.3 High Voltage Insulators

High-voltage insulators are provided on the circuits used to supply power from the switchyard to plant buses during recovery from a station blackout (SBO). The function of high-voltage insulators is to insulate and support electrical conductors.

In LRA Section 3.6.2.1.4, the applicant lists the high-voltage insulators' materials of construction:

- porcelain
- metal (galvanized iron, galvanized steel)
- portland cement porcelain jointing material

The applicant stated that high-voltage insulator components are exposed to an outdoor environment (i.e., component used in transformer yard, switchyard). The applicant also stated that the high-voltage insulators have no AERMs. In Footnote 606 of LRA Table 3.6.2-1, Electrical and I&C Systems - Summary of Aging Management Evaluation - Electrical/I&C Components/Commodities, the applicant stated that surface contamination is not an applicable aging mechanism. The buildup of surface contamination is typically a slow, gradual process. BSEP is located in a rural area where airborne particle concentrations are comparatively low. Consequently, the rate of contamination buildup on the insulators is not significant. Any such contamination accumulation is washed away naturally, by rainwater. The glazed surface on high-voltage insulators aids in the removal of this contamination. In March 1993, the Unit 2 switchyard experienced a flashover of some high-voltage insulators. The incident was attributed to a severe winter storm with gale force winds that persisted in the area for a number of days. The incident was considered a highly unusual atmospheric event and was not attributed to actual aging of the insulators but rather to the storm itself. The storm was unusual because it contained high winds but little or no precipitation to wash away the salt spray on the insulators. An event like this had not occurred prior or subsequent to March 1993. As the March 1993 incident was event-driven, it is concluded that surface contamination is not an applicable stressor for the high-voltage insulators within the scope of this review when exposed to normal service conditions. Therefore, no aging management activities are required for the extended period of operation. This event resulted in the issuance of IN 93-95, "Storm-Related Loss of Offsite Power Events Due to Salt Buildup on Switchyard Insulators."

The applicant also stated that cracking is not an applicable aging mechanism. Cracking or breaking of porcelain insulators is typically caused by physical damage which is event-driven rather than an age-related mechanism. Mechanical wear is an aging effect for strain and suspension insulators if they are subject to significant movement. BSEP transmission conductors do not normally swing and when they do, because of strong winds, they dampen quickly once the wind has subsided. Loss of material due to wear has not been identified during routine inspections at BSEP. The applicant concluded that no aging management activities are required for this commodity group.

Aging Effects. Because there are no AERMs, the applicant stated that no AMPs are required for high-voltage insulators.

In RAI 3.6.2.3-3, dated May 18, 2005, the staff's requested that the applicant provde the following information:

> Various airborne materials such as dust, salt and industrial effluent can contaminate insulator surfaces. A large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flash over. Surface contamination can be a problem in areas where there are greater concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. Industry operating experience identified the potential of loss of offsite power due to salt contamination of switchyard insulators at other plants beside BSEP. On March 17, 1993, Crystal River Unit 3 experienced a loss of the 230 kV switchyard (normal off-site power to safety-related busses) when a light rain caused arcing across salt-laden 230 kV insulators and opened breakers in switchyard. Since 1982, Pilgrim station has also experienced several loss of offsite power events when heavy ocean storms deposited salt on the 345 kV switchyard causing the insulator to arc to ground. In light of these industry operating experiences, provide an AMP to manage the aging effects of insulator or provide a justification of why an AMP is not necessary.

In its response, by letter dated June 14, 2005, the applicant stated:

> Surface contamination on BSEP high-voltage insulators is an applicable aging mechanism that requires management. A silicon-based coating has been applied to the 230KV porcelain insulators to prevent the buildup of surface contamination. As part of the PM Program AMP, the silicon-based coating on the switchyard insulators will be tested. This test consists of the application of a water mist to verify that water beads are present. An initial performance interval of once every refueling outage will be established for this inspection. Should test results warrant an additional coating of silicon, the first inspection following reapplication may be extended. Subsequent inspections after the initial inspection will occur every refueling outage. This test will become part of the PM Program described in Section A.1.1.32 of the LRA. The program description for the PM Program described in Section B.2.30 of the LRA is amended by this response as follows:

System	PM Program Activity
230KV Switchyard System	Inspect high-voltage insulators for water beading on silicone coating and for age related degradation.

The staff found the applicant's response acceptable; therefore, the concern described in RAI 3.6.2.3-3 is resolved.

Aging Management Program. The applicant revised the PM Program described in LRA Section B.2.30 to include the inspection of high-voltage insulators to address the staff's concern about the potential for loss of offsite power due to salt contamination of switchyard insulators. The staff's evaluation of this AMP is in SER Section 3.0.3.3.3.

On the basis of its review, the staff concluded that the applicant adequately addressed the aging threat to high-voltage insulators and has an adequate program for management of the aging effects of high-voltage insulators.

3.6.2.3.4 Switchyard Bus

Switchyard bus provides a portion of the circuit supplying power from the switchyard to plant buses during recovery from an SBO. The function of switchyard bus is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals.

Aging Effects. In LRA Section 3.6.2.1.5, the applicant lists aluminum and galvanized steel as the materials of construction for the switchyard bus components. The switchyard bus components are exposed to outdoor (switchyard) environment but have no AERMs. The applicant stated in Table 3.6.2-1, Footnote 607, that the connections' surface oxidation is not an applicable aging effect. All switchyard bus connections have welded and/or compression connections. For the service conditions encountered at BSEP, no aging effects have been identified that could cause a loss of intended function. Vibration is not an applicable aging mechanism since switchyard bus has no connections to moving or vibration equipment. Switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulator mounted to static; structural components, such as concrete footing; and structural steel. This configuration provides reasonable assurance that switchyard bus will perform its intended function for the extended period of operation.

The applicant stated that connections' surface oxidation is not an applicable aging effect and that all switchyard bus connections have welded and/or compression connections. The staff questioned this assessment, because loss of material due to corrosion of connections due to surface oxidation is an aging effect of the high-voltage switchyard bus connections.

In RAI 3.6.2.3-4, dated May 18, 2005, the staff requested that the applicant provide a justification why aging effects due to corrosion are not significant to the high-voltage switchyard bus and connections.

In its response by letter dated June 14, 2005, the applicant stated:

> Loss of material due to the corrosion of connections due to surface oxidation is an applicable aging mechanism but is not significant enough to cause a loss of intended function. The components involved in switchyard connections are constructed from cast aluminum, galvanized steel and stainless steel. The switchyard bus is constructed of 5-inch, schedule 80, aluminum pipe. No organic materials are involved. Connections to the switchyard bus are welded. Conductor connections are generally of the compression bolted category. Components in the switchyard are exposed to precipitation. The components in the switchyard do not experience any appreciable aging effects in this environment, except for minor oxidation, which does not impact the ability of the switchyard bus to perform its intended function.

> At BSEP, switchyard connection surfaces are coated with an anti-oxidant compound (i.e., a grease-type sealant) prior to tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connection thus reducing the chances of corrosion. Based on operating experience, this method of installation has been shown to provide a corrosion resistant low electrical resistance connection. Therefore, it is concluded that general corrosion resulting in the oxidation of switchyard connection surface metals is not an AERM at BSEP.

The staff found the applicant's response addressed why general corrosion resulting in the oxidation of switchyard connection surface is not a significant AERM. Therefore, the staff's concern described in RAI 3.6.2.3-4 is resolved.

Aging Management Program. The applicant explained why aging effects of switchyard bus are not significant at BSEP and staff agreed that no AMP for swtichyard bus was required.

On the basis of its review, the staff concluded that the applicant adequately addressed the aging threat to switchyard bus and that no AMP was required.

3.6.2.3.5 Transmission Conductors

Transmission conductors provide a portion of the circuits used to supply power from the switchyard to plant buses during recovery from an SBO. The function of transmission conductors is to provide electrical connection to specified sections of an electrical circuit to deliver voltage, current or signals.

Aging Effects. In LRA Section 3.6.2.1.6, the applicant indicated that the transmission conductors are aluminum conductor steel reinforced (ACSR). The material of construction for the transmission conductor components are aluminum and steel. The transmission conductors are exposed to an outdoor (i.e., components are used in the transformer yard or switchyard) environment. The applicant stated that the transmission conductors have no AERMs. In LRA Table 3.6.2-1, Footnote 608, the applicant stated that loss of conductor strength due to corrosion of ACSR transmission conductor is a very slow process. This process is even slower in rural areas, with generally less suspended particles and SO_2 concentration in the air, than in urban areas. BSEP is located in a rural area where airborne particle concentrations are comparatively low. Consequently, this is not considered a significant contributor to the aging of BSEP transmission conductors. Transmission conductor vibration may be caused by wind loading. Wind loading is considered in the initial design and field installation of transmission conductors and high-voltage insulators throughout the CP&L system. Compression connections to transmission conductors are equipped with Belleville washers which provide vibration absorption and prevent loosening. Loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not considered applicable aging effects that warrant aging management. The applicant concluded that no aging management activities are required for this commodity group.

In RAI 3.6.2.3-5, dated May 18, 2005, the staff stated that the most prevalent mechanism contributing to loss of high-voltage transmission conductor strength is corrosion, which includes corrosion of steel core and aluminum strand pitting. The applicant stated that loss of conductor strength due to corrosion of ACSR transmission conductor is a very slow process; however, the applicant failed to provide the technical basis for this conclusion. Therefore, the staff requested that the applicant provide a technical basis for why loss of conductor strength due to corrosion of ACSR transmission conductor is not significant.

In its response, by letter dated June 14, 2005, the applicant stated:

> Loss of transmission conductor strength due to corrosion is an applicable aging effect, but ample design margin ensures that it is not significant enough to cause a loss of intended function. BSEP transmission conductors are Type ACSR (i.e., aluminum conductor steel reinforced). They are constructed of strand aluminum conductors wound around a steel core. No organic materials are involved. The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR transmission conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality, which includes suspended particle chemistry, SO2 concentration in air, precipitation, fog chemistry, and meteorological conditions. Corrosion of ACSR transmission conductors is a very slow process that is even slower for rural areas with generally fewer suspended particles and lower SO2 concentrations in the air than urban areas. BSEP is located in a rural area where airborne particle concentrations are comparatively low. Consequently, this is not considered a significant contributor to this aging mechanism.
>
> There is a set percentage of composite conductor strength established at which a transmission conductor is replaced. The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. Tests performed by Ontario Hydroelectric showed a 30% loss of composite conductor strength of an 80-year-old transmission conductor due to corrosion. Assuming a 30% loss of strength, there would still be significant margin between what is required by the NESC and actual conductor strength.
>
> These requirements were reviewed concerning the specific transmission conductors used at BSEP. BSEP is in the medium loading zone; therefore, the Ontario Hydroelectric heavy loading zone study is conservative. The BSEP transmission conductors with the smallest ultimate strength margin, i.e., 1272 MCM ACSR, will be used as an illustration. The ultimate strength of 1272 MCM ACSR is 34,100 lbs and the maximum heavy load tension of 1272 MCM ACSR is 3,000 lbs. The margin between the heavy load tension and the ultimate strength is 31,100 lbs.; therefore, there is a 91% ultimate strength margin (i.e., 31,100/34,100). The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80-year-old conductor. In the case of the 1272 MCM ACSR transmission conductors, a 30% loss of ultimate strength would mean that there would still be a 61% ultimate strength margin between what is required by the NESC and the actual conductor strength in an 80-year old conductor.
>
> The BSEP transmission conductors within the scope of License Renewal are short span lengths located entirely within the switchyard area. The spans are approximately 287 feet in length. Therefore, the tension exerted on these conductors is less than would be experienced in typical applications, which could be up to 1000 feet in length.

> The foregoing discussion illustrates that there is ample design margin in the transmission conductors at BSEP. Based on the conservatism in the ultimate strength margin, it is concluded that loss of conductor strength is not an AERM at BSEP.

The staff found the applicant’s response adequately addressed why loss of conductor strength due to corrosion is not a significant AERM at BSEP. Therefore, the staff’s concern described in RAI 3.6.2.3-6 is resolved.

Aging Management Program. The applicant clearly explained why loss of conductor strength due to corrosion of transmission conductors is not a significant AERM and the staff agreed that no AMP for transmission conductors is required.

On the basis of its review, the staff concluded that the applicant adequately addressed the aging threat to transmission conductors and that no AMP is required.

3.6.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components, that are within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR supplement program summaries and concludes that they adequately describe the AMPs credited for managing aging of the electrical and I&C components, as required by 10 CFR 54.21(d).

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 <u>Identification of Time-Limited Aging Analyses</u>

This section discusses the identification of time-limited aging analyses (TLAAs). The applicant discusses the TLAAs in license renewal application (LRA) Sections 4.2 through 4.7. Safety evaluation report (SER) Sections 4.2 through 4.8 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

The TLAAs are certain plant-specific safety analyses that are based on an explicitly assumed 40-year plant life. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* [10 CFR 54.21(c)(1)], the applicant for license renewal must provide a list of TLAAs, as defined in 10 CFR 54.3.

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant must provide a list of plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for the Brunswick Steam Electric Plant (BSEP) against the six criteria specified in 10 CFR 54.3. The applicant indicated that it had identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), engineering calculations, technical reports, engineering work requests, licensing correspondence, and applicable vendor reports. The applicant listed the following applicable TLAAs in LRA Table 4.1-1, “Time-Limited Aging Analyses:”

- reactor vessel neutron embrittlement
- metal fatigue
- environmental qualification of electrical equipment
- concrete containment tendon prestress
- containment liner plate, metal containments, and penetrations fatigue analysis
- Service Level 1 coating qualification
- fuel pool girder tendon loss of prestress
- crane, refueling platform, and monorail hoist cyclic load limits
- torus component corrosion allowance

Pursuant to 10 CFR 54.21(c)(2), the applicant identified exemptions granted under 10 CFR 50.12 that were based on a TLAA, or TLAAs, as defined in 10 CFR 54.3. The applicant identified a single exemption associated with TLAAs in LRA Section 4.1.3, “Identification of Exemptions.” The exemption involves an analysis for the development of revised reactor vessel pressure-temperature (P-T) curves using alternative fracture toughness methods.

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to Units 1 and 2; the applicant also discussed exemptions based on these TLAAs. The staff reviewed the information to determine if the applicant had provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As defined in 10 CFR 54.3, TLAAs are analyses that meet the following six criteria:

(1) involve systems, structures, and components that are within the scope of license renewal, as delineated in 10 CFR 54.4(a)

(2) consider the effects of aging

(3) involve time-limited assumptions defined by the current operating term (40 years)

(4) are determined to be relevant by the applicant in making a safety determination

(5) involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b)

(6) are contained or incorporated by reference in the CLB

The applicant provided a list of common TLAAs from NUREG-1801, “Generic Aging Lessons Learned (GALL) Report, and NUREG-1800, “Standard Review Plan for the Review of License Renewal Applications,” (SRP-LR). In LRA Table 4.1-1, “Time-Limited Aging Analyses,” the applicant listed TLAAs that are applicable to Units 1 and 2.

As required by 10 CFR 54.21(c)(2), an applicant must provide a list of all the exemptions granted under 10 CFR 50.12 that are based on a TLAA and evaluated and justified for continuation through the period of extended operation. In its LRA, the applicant stated that each active exemption was reviewed to determine whether the exemption was based on a TLAA. The applicant identified TLAA-based exemptions. On the basis of the information provided by the applicant with regard to the process used to identify TLAA-based exemptions, as well as the results of the applicant’s search, the staff found that BSEP letter 01-0034 (Accession No. ML011280090) to the NRC dated May 1, 2001, requested an exemption from the requirements of 10 CFR 50, Appendix G. BSEP proposed to use ASME Code Case-640 in lieu of Appendix G of ASME Code Section XI for the generation of updated pressure-temperature (P-T) limit curves. NRC letter (Accession No. ML012760157), dated October 3, 2001, approved the exemption and the use of Code Case-640 for development of the curves. The exemption applied for the development of P-T limit curves applicable for 32 effective full power years (EFPY), which corresponds with 40 years of operation. These P-T limit curves were determined to be a TLAA.

In order to evaluate this TLAA for 60 years, new P-T limit curves applicable for 54 EFPY were developed which determined that adequate operational margins will exist when these curves apply in the future. However, these 54 EFPY curves were not submitted for NRC approval as a part of the LRA and no new Exemption Request was prepared at that time. Rather, new P-T limit curves will be submitted for NRC review and approval at least one year prior to the expiration of the 32 EFPY curves. If a new Exemption Request is needed to support the methods used to develop the new P-T limit curves, it will also be submitted for staff review and approval at that time.

4.1.3 Conclusion

On the basis of its review, the staff found that the applicant provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1), and the staff determined that the applicant will submit the 54 EFPY P-T limit curves for BSEP in accordance with the 10 CFR 50.90 license amendment process prior to expiration of the 32 EFPY P-T limit curves that are currently approved in the BSEP Technical Specification (TS). The staff found that when the 54 EFPY P-T limit curves are submitted, the existing license amendment process will enable the staff to verify that the P-T limits for 54 EFPY will be in compliance with the criteria of 10 CFR Part 50, Appendix G, and with the staff's acceptance criterion for TLAAs, as defined in 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also found that the UFSAR supplement contains an appropriate summary description of the TLAA on P-T limits for the periods of extended operation, as required by 10 CFR 54.21(d).

4.2 Reactor Vessel Neutron Embrittlement

Neutron embrittlement is the term used to describe changes in mechanical properties of reactor vessel materials that result from exposure to fast neutron flux (E > 1.0 MeV) within the vicinity of the reactor core, called the beltline region. The most pronounced material change is a reduction in fracture toughness. As fracture toughness decreases with cumulative fast neutron exposure, the material's resistance to crack propagation decreases. Fracture toughness of ferritic materials is dependent not only upon fluence but also upon temperature. The reference temperature for the nil-ductility temperature, nil-ductility transition (RT_{NDT}) is the temperature above which the material behaves in a ductile manner, and below which it behaves in a brittle manner. As fluence increases, the nil-ductility reference temperature increases. This means higher temperatures are required for the material to continue to act in a ductile manner. This shift in reference temperature is the RT_{NDT} plus a margin term, which is added to account for uncertainties associated with the limited amount of data available for making the projections. The projected reduction in fracture toughness as a function of fluence impacts several analyses used to support operation of BSEP:

- reactor pressure vessel (RPV) fluence
- RPV material upper-shelf energy (USE)
- RPV adjusted reference temperature (ART)
- RPV operating P-T limits
- RPV circumferential weld examination relief
- RPV axial weld failure probability
- core shroud reflood thermal shock analysis
- core plate plug spring stress relaxation
- core shroud repair hardware analysis

Since extending the operating period from 40 years to 60 years will further increase the fluence levels, the 60-year fluence value must be determined and used to determine its impact upon USE and ART calculations, P-T limit curves, analyses supporting RPV circumferential weld examination relief, reflood shock analyses, and core plate plug spring relaxation.

The staff uses two parameters as a measure of the fracture toughness of ferritic steels (i.e., either carbon steel or low-alloy steel) used to fabricate the reactor vessels (RVs) in light-water reactors:

(10) An adjusted reference temperature for nil-ductility transition (RT_{NDT} value), which is a measure of the material's ability to resist cleavage failure.

(11) The USE value for the material, which is a measure of the material's ability to resist ductile failure.

During plant service, neutron radiation reduces the fracture toughness of the RV materials by causing the following effects on the fracture toughness properties: (1) the material's RT_{NDT} value increases, and (2) the material's USE value decreases. For RVs, the base metal materials and weld materials in the region of the vessel immediately adjacent to the reactor core (i.e., in the beltline region of the RV) are most susceptible to these effects because they are exposed to radiation in excess of a neutron fluence of 1.0×10^{17} neutrons/cm^2
(n/cm^2 [E > 1.0 MeV]). The neutron radiation doses are time-dependent parameters. Thus changes in the accumulated neutron radiation doses will require periodic updates of the structural integrity analyses that are required for the boiling water reactor (BWR) RV beltline components and for some of the RV internal components.

The applicant identified that the following plant-specific assessments met the definition for TLAAs, as based on identification that neutron fluence is a time-dependent parameter and on the remaining criteria for TLAAs in 10 CFR 54.3.

- LRA Section 4.2.1 ! TLAA on Neutron Fluence
- LRA Section 4.2.2 ! TLAA on USE, including Section 4.2.2.1 on RV beltline plate and weld materials and Section 4.2.2.2 on the RV nozzle forgings
- LRA Section 4.2.3 ! TLAA on the calculation of the adjusted reference temperatures that are used as inputs to the P-T limit calculations
- LRA Section 4.2.4 ! TLAA on the calculation of the pressure-temperature (P-T) limit curves
- LRA Section 4.2.5 ! TLAA on the calculation of the mean RT_{NDT} values for the RV circumferential weld relief request analyses
- LRA Section 4.2.6 ! TLAA on the calculation of the mean RT_{NDT} values for the RV axial weld failure probability analyses
- LRA Section 4.2.7 ! TLAA on the core shroud thermal reflood analysis
- LRA Section 4.2.8 ! TLAA on the RV core plate plug spring stress relaxation analysis
- LRA Section 4.2.9 ! TLAA on the RV core shroud repair hardware analysis

The staff's assessment of these TLAAs is given in the corresponding sections of the staff's SER on the LRA for BSEP. The staff issued request for information (RAI) 4.2-1, dated April 8, 2005, to request clarifying information on the neutron radiation TLAAs for the RV N!16 instrumentation nozzle welds and to request confirmatory data on these materials. The resolution of RAI 4.2-1 with respect to the 54 EFPY USE analysis for the N!16 instrumentation nozzle welds is evaluated in SER Section 4.2.2.2. The resolution of RAI 4.2-1 with respect to the 54 EFPY 1/4T RT_{NDT} analysis for the N!16 instrumentation nozzle welds is evaluated in SER Section 4.2.3.2.

The staff issued RAI 4.2-2, dated April 8, 2005, to inquire whether the RV reflood thermal shock analysis, as defined in UFSAR Section 5.3.3.1.3, should be a TLAA for the LRA. In its response, by letter dated May 4, 2005, the applicant identified that the RV reflood thermal shock analysis in UFSAR Section 5.3.3.1.3 did meet the definition of a TLAA, as defined in 10 CFR 54.3. The applicant included a discussion of this TLAA in its response to RAI 4.2-2. The discussion includes the applicant's basis for concluding that the TLAA on RV reflood thermal shock analysis is acceptable when evaluated under the acceptance criterion of 10 CFR 54.21(c)(1)(ii). The staff evaluated the TLAA on RV reflood thermal shock analysis and the applicant's response to RAI 4.2-2 in SER Section 4.2.10. SER Section 4.2.10 provides the staff's basis for accepting the TLAA on RV reflood thermal shock analysis under the acceptance criterion of 10 CFR 54.21(c)(1)(ii).

4.2.1 Neutron Fluence

In LRA Section 4.2.1, the applicant stated that the calculation of the neutron fluence values for the RVs and RV internal components meets the definition of a TLAA, as defined in 10 CFR 54.3. Henceforth, the staff will refer to this TLAA as the "TLAA on neutron fluence calculations."

4.2.1.1 Technical Information in the Application

In LRA Section 4.2.1, the applicant provided the following assessment of the TLAA on neutron fluence calculations:

> **4.2.1 NEUTRON FLUENCE**
>
> The rate of neutron exposure is called the neutron flux, and the cumulative degree of neutron exposure is called the neutron fluence. Neutron flux is a function of reactor power level, and is measured continuously. Neutron fluence projections including the period of extended operation are required to permit determination of the effect of the increased neutron exposure upon reactor vessel material properties. Neutron fluence projections are made based upon measured flux data from past operation and projected power levels and operating efficiency estimates for future operation. Cavity dosimetry has been utilized at BSEP in the past to provide further confirmation of fluence values during previous operation. In addition, one surveillance capsule has been removed from each unit that provided dosimetry information that is used to measure past fluence. These data have been used in developing a fluence projection calculation which predicts the cumulative fluence for the reactor vessel and internals in BSEP Unit 1 and 2 for 54 effective full power years (EFPY), which bounds 60 years of operation. The methodology for fluence projections must meet the requirements of Regulatory Guide 1.190.
>
> **Analysis**
>
> A calculation has been performed to determine fluence projections applicable for the reactor vessel and internals for the current operating term and at 54 EFPY, which bounds 60 years of operation. This fluence analysis was prepared by Westinghouse Electric Corporation (W) for BSEP Units 1 and 2, and was used as the basis for developing Pressure-Temperature Limit Curves for up to 32 EFPY. The 32 EFPY P-T limit curves were submitted to and approved by the NRC for use at BSEP in a Safety Evaluation Report provided in NRC letter (B. Mozafari) to BSEP (J. Keenan) dated June 18, 2003: "Brunswick Steam Electric Plant, Units 1 and 2, Issuance of Amendment re: Pressure-Temperature Limit Curves (TAC Nos. MB5579 and MB5580)." Section 3.4 of the NRC Safety Evaluation Report states:
>
>> *This plant-specific benchmark is the most relevant and indicates that the W methodology satisfies the RG 1.190 guidelines, and is acceptable for BSEP plant-specific applications.*

Because W used a qualified methodology, the calculated fluence values for 32 EFPY are acceptable.

While the P-T limit curves were based on 32 EFPY fluence projections, validation of the fluence methodology by the NRC also applies to the 54 EFPY fluence projections, because they are further extensions of the same analysis, and have the same basis. The W fluence evaluation considers the effects of EPU and is projected for 54 EFPY. Therefore, the neutron fluence has been projected to the end of the period of extended operation using a methodology previously reviewed and approved by the NRC. The 54 EFPY fluence projections will be used for evaluating fluence-based TLAAs for BSEP License Renewal.

Disposition: 10 CFR 54.21(c)(1)(ii) – The neutron fluence analyses have been projected to the end of the period of extended operation.

The applicant's 54 EPFY neutron fluence values for the clad-base-metal interface and 1/4T locations of the BSEP RVs are given in Table 4.2-5 for Unit 1 and Table 4.2-6 for Unit 2.

4.2.1.2 Staff Evaluation

Regulatory Evaluation. The staff issued regulatory guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," in March 2001. The RG provides guidance regarding acceptable methods for benchmarking neutron fluence methodologies based on the requirements of General Design Criterion (GDC) 31 and, in part, on GDCs 14 and 30. Therefore, the staff based its review of the neutron fluence evaluations for BSEP on the adherence of the applicant's calculational method to the guidance in RG 1.190.

Technical Evaluation. The Westinghouse Electric Company submitted a plant-specific methodology for the calculation of neutron fluences for the RV and RV internal components. The methodology included qualification techniques on both the generic Westinghouse and BSEP plant-specific neutron fluence methodologies. The generic qualifications included the NRC BWR benchmark problem from NUREG/CR-6115 (Reference 1) and a demonstration of the specific code features. The BSEP plant-specific qualification included the neutron fluence analyses from the test results of two BSEP plant-specific surveillance capsules. The calculated surveillance capsule results were compared to the results of the dosimetry surveillance data and demonstrated excellent agreement with the measured values. The staff determined that the Westinghouse methodology adheres to the guidance of RG 1.190 and, therefore, approved the BSEP plant-specific neutron fluence methodology for the RV and RV internals fast (E > 1.0 MeV) fluence calculations. This methodology was approved by the staff in the NRC letter and safety evaluation (SE) of January 14, 2004, "Brunswick Steam Electric Plant, Units 1 and 2 - Issuance of Amendments Regarding the Boiling Water Reactor Vessel and Internals Project Reactor Pressure Vessel Integrated Surveillance Program (TAC Nos. MC0254 and MC0255)." The applicant's 54 EFPY neutron fluence values for the RV and RV internal components are based on the NRC-approved Westinghouse methodology. Since the 54 EFPY neutron fluence values conform to the recommendations in RG 1.190, the staff found that the applicant's 54 EFPY neutron fluence values are acceptable to use for the applicant's TLAA on neutron fluence calculations. Based on this assessment, the staff found that the applicant has projected the neutron fluence values for BSEP through the expiration of the period of extended operation as required by 10 CFR 54.21(c)(1)(ii) and that the 54 EFPY neutron fluences for BSEP are, therefore, acceptable.

4.2.1.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the TLAA on the neutron fluence calculations:

> **A.1.2.1 Reactor Vessel Neutron Embrittlement**
>
> Calculations have been performed to determine neutron fluence projections applicable to the reactor vessel and internals at 54 EFPY, which bounds 60 years of operation, using an NRC-approved methodology. The fluence projections have been used in the following analyses.

The UFSAR supplement summary description in LRA Section A.1.2.1 indicates that the neutron fluences for the periods of extended operation have been calculated using a staff-approved methodology. The methodology discussed in the UFSAR supplement refers to the neutron fluence methodology that was submitted in Carolina Power & Light Company (CP&L) Serial Letter No. BSEP-03-0062, dated May 29, 2003. This methodology was approved by the staff in the NRC letter and safety evaluation (SE) of January 14, 2004, “Brunswick Steam Electric Plant, Units 1 and 2 - Issuance of Amendments Regarding the Boiling Water Reactor Vessel and Internals Project Reactor Pressure Vessel Integrated Surveillance Program (TAC Nos. MC0254 and MC0255).” In this SE, the staff concluded that the methodology applied by the applicant to calculate the neutron fluences for the RVs and RV internals was based on an acceptable plant-specific basis that conformed to the recommended guidelines in RG 1.190. Since the methodology referred to in the UFSAR supplement summary description has been approved by the staff and conforms to the RG 1.190 recommendations, the staff found the UFSAR supplement summary description for the TLAA on neutron fluence calculations is acceptable and complies with 10 CFR 54.21(d).

4.2.1.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the neutron fluence TLAA, the analyses have been projected to the end of the period of extended operation.. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the neutron fluence TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.2 Upper Shelf Energy Evaluation

In LRA Section 4.2.2, the applicant stated that the calculation of USE values for the RV beltline materials meets the definition of a TLAA as defined in 10 CFR 54.3. Henceforth the staff will refer to this TLAA as the “TLAA on USE/EMA” because the applicant’s TLAA analysis relies on satisfying the equivalent margin analysis (EMA) provisions that are stated in Section IV.A.1 of 10 CFR Part 50, Appendix G.

4.2.2.1 Technical Information in the Application

The applicant provided the following assessment of the TLAA on USE/EMA:

> **4.2.2 UPPER SHELF ENERGY EVALUATION**

4.2.2.1 Reactor Vessel Plates and Welds

Summary Description

Upper-shelf energy (USE) is the standard industry parameter used to indicate the maximum toughness of a material at high temperature. 10 CFR 50, Appendix G, requires that the upper shelf Charpy V-notch energy of the reactor vessel beltline region be greater than 75 ft-lbs initially, and remain above 50 ft-lbs throughout the operating license of the plant. However, the Charpy tests performed on BSEP reactor vessel materials under the code of record provided limited Charpy impact data. It was not possible to develop original Charpy impact test USE values using the ASME III NB-2300, Summer 1972 (and later) methods invoked by 10 CFR 50 Appendix G. Since this minimum requirement is not achieved, a licensee is required to demonstrate that lower values of USE will provide margins of safety against fracture equivalent to those required by the ASME Code Section XI, Appendix G.

For plates and welds, end-of-life fracture energy was evaluated during the current license period by using the equivalent margin analysis (EMA) methodology described in NEDO-32205-A. This methodology was approved by the NRC as documented in a letter from the BWR Owners' Group (L. England) to the USNRC (D. McDonald), dated March 24, 1994: "BWR Owners' Group Topical Report on Upper Shelf Energy Equivalent Margin Analysis – Approved Version," BWROG-94037, (Accession No 94038280161). This analysis confirmed that an adequate margin of safety against fracture, equivalent to 10 CFR 50 Appendix G requirements, does exist. The end-of-life upper-shelf energy calculations satisfy the criteria of 10 CFR 54.3(a). Since these calculations are based upon 40-year fluence values, they are TLAAs.

Analysis

Sixty-year fluence values were calculated for BSEP Units 1 and 2 using the NRC approved methodology discussed in Subsection 4.2.1 above. Peak fluence values were first calculated at the vessel inner surface (inner diameter). However, for purposes of evaluating USE for 60 years within this calculation, the value of neutron fluence was also calculated for the ¼T location into the vessel wall measured radially from the inside diameter (ID), using Equation 3 from Paragraph 1.1 of Regulatory Guide 1.99, Revision 2. This ¼T depth is recommended in the ASME Boiler and Pressure Vessel Code Section XI, Appendix G, 1998 Edition, Addendum 2000, Sub-article G-2120, as the maximum postulated defect depth.

BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," June, 2003, performs a generic analysis and determines that the percent reduction in Charpy USE acceptable for the limiting BWR/3-6 plates and BWR/2-6 welds are 23.5% and 39% respectively. BWRVIP-74-A has been approved by the NRC for use in License Renewal. The USE values for BSEP materials were evaluated by an EMA using the 54 EFPY calculated fluence and BSEP surveillance capsule results. The results of the EMA for limiting plates and welds on the reactor vessels are shown on Table 4.2-1 and 4.2-2 for Unit 1 and Table 4.2-3 and 4.2-4 for Unit 2. The results are also compared to the limits from BWRVIP-74-A. The results show that the limiting Charpy USE EMA percent reduction is less than the BWRVIP-74-A acceptance criteria in all cases. Therefore, a 60-year USE EMA for BSEP plates and welds has been prepared using a methodology previously reviewed and approved by the NRC, and the results meet the applicable acceptance criteria in all cases. Thus, the USE values for plates and welds have been satisfactorily projected through the end of the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(ii) – The USE analyses for RPV plates and welds have been projected to the end of the period of extended operation.

4.2.2.2 Reactor Vessel Nozzle Forgings

Summary Description

In its response to Generic Letter 92-01, Revision 1, Supplement 1, dated November 16, 1995, BSEP committed to provide a plant-specific upper shelf energy (USE) equivalent margins analysis for each of the BSEP reactor pressure vessel N16 forged nozzles. Each reactor vessel contains two 2-inch nominal pipe size forged instrument nozzles, N16A and N16B, within the upper beltline region. BSEP performed a plant-specific equivalent margin analysis as required by 10 CFR 50, Appendix G. The analysis showed that the N16 nozzles for both reactor vessels should have had an initial, unirradiated USE (UUSE) of at least 70 ft-lbs, based on an extensive database search. In addition, the USE was not anticipated to drop more than 18% for either reactor vessel, based upon a conservative projection of the end-of-life fluence of 1.6E+18 n/cm^2. Therefore, the end-of-life USE of the nozzles for both vessels was anticipated to remain higher than the minimum screening criterion of 50 ft-lbs.

For added conservatism, an equivalent margins analysis (EMA) was also performed per the guidelines provided in USNRC Regulatory Guide 1.161. This analysis demonstrated that the N16 nozzles would meet the ASME Code, Section XI, Appendix K, and Regulatory Guide 1.161 J-R fracture toughness requirements with an end-of-life USE as low as 29 ft-lbs. It was also shown that a 29 ft-lb end-of-life USE value would be equivalent to an initial USE of 35 ft-lbs, conservatively assuming the 18% drop in USE over the life of the vessels. As noted above, it has been shown that the subject nozzle material should have an initial USE of at least 70 ft-lbs.

On October 16, 1998, the NRC provided its Safety Evaluation. Refer to NRC letter (D. Trimble) to BSEP (J. Keenan), dated October 16, 1998: "Evaluation of the January 17, 1992, Operating Transient at the Brunswick Steam Electric Plant, Unit 1, and Evaluation of Carolina Power & Light Company's Equivalent Margins Analysis of the N-16A/B Instrument Nozzles at the Brunswick Steam Electric Plant, Units 1 and 2 (TAC Nos. MA0399/400)."

The NRC staff concluded the following:

The staff has determined that CP&L's USE evaluation of the No. N-16NA/B instrument nozzles represents a sufficiently conservative assessment of the fracture toughness properties of the nozzles. CP&L's assessment indicates that USE of the nozzles will not fall below the 50 ft-lb value required by the rule at the EOL for the plants. However, since the UUSE for the nozzles has been estimated in the case, CP&L has shown the instrument nozzles should have sufficient protection against ductile tearing, down to a value of 29 ft-lbs. By the staff's calculations, the nozzles should have sufficient margin down to at least a value of 30 ft-lb. These values are not statistically different. The EMAs for the nozzles therefore indicate that even if the EOL USE were lower than the 50 ft-lbs required by the rule, the nozzles have sufficient margin against fracture at USE values lower than those required by the rule, and that the nozzles therefore satisfy the EMA criteria stated in 10 CFR Part 50, Appendix G. Therefore, the staff concludes that CP&L's method for establishing the UUSE and EOL USE values (70 ft-lb and 57.4 ft-lb, respectively) for the nozzle forgings, when coupled with the results of CP&L's EMA for the nozzle forgings, is sufficiently conservative in this case, and therefore, is acceptable.

Since the equivalent margins analysis for the nozzle forgings was based upon a fluence value assumed for 40 years of operation, the analysis is considered to be a TLAA requiring evaluation for 60 years.

Analysis

The 60-year fluence calculation, discussed in Subsection 4.2.1 above, provides a predicted end-of-life fluence for the N16 nozzles of 1.38E+18 n/cm^2 for 54 EFPY. This 60-year value is below the value of 1.6E+18 n/cm^2 used in the equivalent margin analysis for the N16 nozzles that has already been reviewed and approved by the NRC. Therefore, the USE equivalent margin analysis for the N16 nozzle forgings has been demonstrated to remain valid for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(i) – The USE equivalent margins analyses for the RPV nozzle forgings remain valid through the end of the period of extended operation.

4.2.2.2 Staff Evaluation

Regulatory Evaluation. Requirements for USE in 10 CFR Part 50, Appendix G, Section IV.A.1, requires RV beltline materials to have Charpy USE values that are greater than or equal to 75 ft-lb (102 J) initially and greater than or equal to 50 ft-lb (68 J) throughout a facility's licensed operating period, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will ensure margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

Additional Regulatory Guidance in the NRC SER on Topical Report Boiling Water Reactor Vessel and Internals Program (BWRVIP)-74, as Applicable to TLAAs on P-T Limits

On September 21, 1999, the BWRVIP submitted Topical Report TR-1113596, “BWRVIP-74: BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal” (BWRVIP-74). In Appendix B of this topical report, the BWRVIP assessed the license renewal actions that would be needed to demonstrate that plant-specific EMAs on USE would be acceptable for the period of extended operation. The staff provided its final SER (FSER) on BWRVIP-74 on October 18, 2001. In this FSER, the staff established the following position regarding acceptance of TLAAs on USE/EMA:

> Section IV.A.1a. of Appendix G to 10 CFR Part 50 requires, in part, that RPV beltline materials shall have Charpy USE in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb (68J), unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.
>
> By letter dated April 30, 1993, the Boiling Water Reactor Owner’s Group (BWROG) submitted a topical report entitled “10 CFR 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels,” to document that BWR RPVs could meet the margins of safety against fracture equivalent to those required by Appendix G of the ASME Code for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the staff concluded that the topical report demonstrated that the materials evaluated had the margins of safety against fracture equivalent to Appendix G of the ASME Code, in accordance with Appendix G of 10 CFR Part 50. In this report, the BWROG derived through statistical analysis the initial USE values for materials that originally did not have documented Charpy USE values. Using these statistically derived Charpy USE values, the BWROG predicted the end-of-life (40 years of operation) USE values in accordance with RG 1.99, Revision 2 (RG 1.99, Rev. 2). According to this RG, the decrease in USE is dependent upon the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE in the transverse direction for base metal and along the weld for weld metal was 35 ft-lb.
>
> Appendix B in the BWRVIP-74 report provides a bounding Charpy USE for BWR plants for 54 EFPY. The BWRVIP-74 analysis utilized an unirradiated Charpy USE in the longitudinal direction of 91 ft-lb for BWR/3-6 plates and 70.5 ft-lb for non-Linde 80 submerged arc welds. The value for the plates is the lowest value from the database and is less than the lower 95/95 confidence value. The value for the non-Linde 80 submerged arc welds is the value corresponding to the lower 95/95 confidence value. Since these values are statistically determined with at least 95/95 confidence, these values may be used in the evaluation of Charpy USE.

The analysis in the BWRVIP-74 report determined the reduction in the unirradiated Charpy USE resulting from neutron radiation using the methodology in RG 1.99, Rev. 2. Using this methodology and using a correction factor of 65 percent for conversion of the longitudinal properties to transverse properties, the lowest irradiated Charpy USE at 54 EFPY for all BWR/3-6 plates is projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical position MTEB 5-2. Using the RG methodology the lowest irradiated Charpy USE at 54 EFPY for BWR non-Linde 80 submerged arc welds is projected to be 43 ft-lb. The BWRVIP-74 report indicates that the percent reduction in Charpy USE for the limiting BWR/3-6 plates and BWR non-Linde 80 submerged arc welds are 23.5 percent and 39 percent, respectively. To demonstrate that the beltline materials meet the criteria specified in the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2. This is Renewal Applicant Action Item 10.

NRC's Plant-Specific Regulatory Basis for Approving an Equivalent Margins Analysis for the BSEP N16 Instrumentation Nozzles

On April 14, 1997, the applicant submitted a plant-specific USE/EMA assessment for the BSEP N!16 instrumentation nozzles. In this submittal, the applicant projected that the USE value for the BSEP N!16 instrumentation nozzles in the unirradiated condition (i.e., unirradiated USE value, henceforth termed as the UUSE value) was 70 ft-lb. Using a projected neutron fluence of 1.6 x 10^{18} n/cm^2 (E > 1.0 MeV), the applicant projected the USE value for BSEP N!16 instrumentation nozzles to be 57.4 ft-lb at end of life (32 EFPY), which complies with the 50 ft-lb acceptance criterion in 10 CFR Part 50, Appendix G, for ferritic RV materials. The applicant also performed an EMA because the UUSE value for the BSEP N!16 instrumentation nozzles was projected to be less than the 75 ft-lb acceptance criterion in 10 CFR Part 50, Appendix G, for ferritic RV beltline materials in the unirradiated condition. In the EMA, the applicant projected that the BSEP N!16 instrumentation nozzles would maintain acceptable levels of USE down to 29 ft-lb at end of life (EOL).

To assess the validity of the applicant's USE and EMA assessments, the staff performed an independent EMA for the BSEP N!16 instrumentation nozzles in accordance with the NRC's recommended EMA methodology of RG 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper Shelf Energy Less Than 50 ft-Lb [June 1995]," and the methodology in ASME Code Section XI, Appendix K, "Assessment of Reactor Vessels with Low Upper Shelf Charpy Impact Energy Levels," as invoked by the RG. These methodologies use elastic-plastic fracture mechanics methods as the bases for evaluating the structural integrity of low USE materials. The staff's evaluation of the applicant's submittal of April 14, 1997, and the results of the staff's independent EMA are given in the staff's SE, dated October 16, 1998, "Evaluation of the January 17, 1992, Operating Transient at the Brunswick Steam Electric Plant, Unit 1, and Evaluation of Carolina Power & Light Company's Equivalent Margins Analysis of the N!16 A/B Instrument Nozzles at the Brunswick Steam Electric Plant, Units 1 and 2 (TAC Nos. MA0399/400)." Based on the staff's independent EMA for the BSEP N!16 instrumentation nozzles, the staff determined that the nozzles would exhibit adequate resistance to failure from ductile tearing down to a USE value of 30 ft-lb. Therefore, the staff concluded that the applicant had provided an acceptable basis for establishing the 70 ft-lb USE value and the 57.4 ft-lb USE value associated with a neutron fluence level of 1.6 x 10^{18} n/cm^2 (E > 1.0 MeV) and for demonstrating that the continued operation of the nozzles down to a USE value of 30 ft-lb was acceptable.

To demonstrate continued applicability of this EMA, the applicant is required to demonstrate either that the limiting neutron fluence for the BSEP N!16 instrumentation nozzles remains below 1.6 x 10^{18} n/cm^2 (E > 1.0 MeV) at the expiration of the period of extended operation, as evaluated in accordance with 10 CFR 54.21(c)(1)(i); or that the limiting USE value for the N!16 instrumentation nozzles remains above 30 ft-lb, as projected out to 54 EFPY and evaluated in accordance with 10 CFR 54.21(c)(1)(ii).

<u>*Technical Evaluation*</u>

Technical Evaluation on the USE / Equivalent Margins Analyses (EMAs) for BSEP RV Beltline Plate and Weld Materials

The applicant's TLAAs on USE/EMA (i.e., the 54 EFPY USE assessments) of the BSEP RV beltline plate and weld materials are given in the following LRA Tables:

- LRA Table 4.2-1 - TLAA on USE/EMA for Unit 1 RV beltline plate materials
- LRA Table 4.2-2 - TLAA on USE/EMA for Unit 1 RV beltline weld materials
- LRA Table 4.2-3 - TLAA on USE/EMA for Unit 2 RV beltline plate materials
- LRA Table 4.2-4 - TLAA on USE/EMA for Unit 2 RV beltline weld materials

The applicant based the acceptability of these TLAAs on the following criteria: (1) conformance with the staff's 54 EFPY acceptance criteria for EMAs in its SE on BWRVIP-74, dated October 18, 2001; (2) demonstration that the USE values for the limiting RV beltline plate and the limiting RV beltline weld material in BWRVIP-74 in each unit are projected to remain above the applicable minimum USE/EMA value criterion at the expiration of the period of extended operation, as evaluated in terms of allowable percent drop in USE through 54 EFPY; and (3) demonstration that the projected percent drop in USE for the limiting RV plate material in BWRVIP-74 and limiting RV weld material bound the projected percent drop in USE calculated for the RV surveillance plate and weld materials at 54 EFPY. The applicant used Position 2.1 of RG 1.99, Revision 2, as the basis for predicting the percent drops for both the RV beltline plates and welds and RV surveillance plates and welds. This is consistent with the staff's methodology for assessing USE values in RG 1.99,
Revision 2.

In Renewal Applicant Action Item 10, the staff stated that BWR license renewal applicants would need to demonstrate that the percent drop in USE values for their limiting RV base metal material and limiting RV weld material, as projected at the expiration of the period of extended operation, remain bounded by the projected percent drop in USE values for these materials, as approved in the staff's SE on BWRVIP-74, dated October 18, 2001. In order to assess the validity of the applicant's calculations, the staff performed independent calculations of the percent drop in USE values for the BSEP RV beltline plate and weld materials, and RV surveillance plate and weld materials, as evaluated through 54 EFPY. The staff used the generic USE values in BWRVIP-74 for BWR RV plate and weld materials and applied the 1/4T neutron fluence values listed in LRA

Table 4.2-5 for Unit 1 and in LRA Table 4.2-6 for Unit 2 as its basis for its independent calculations. The staff applied NRC Position 2.1 in RG 1.99, Revision 2 as the methodology for performing its independent USE calculations. This is consistent with the staff's methodology for assessing USE values in RG, 1.99, revision 2. The 54 EFPY 1/4T neutron fluences used in the staff's independent percent drop in USE calculations are those that have been determined using the methodology approved in SER Section 4.2.1.

For the USE assessment of the Unit 1 RV weld materials, the staff determined that the limiting weld material is Circumferential Weld FG (Heat No. 1P4218). This determination was found to be consistent with the limiting material identified by the applicant. The staff calculated a 14.1 percent drop for this material at 54 EFPY. This is based on use of a 1/4T neutron fluence of 0.032 x 10^{19} n/cm^2 (E > 1.0 MeV) at 54 EFPY. In comparison, the applicant calculated a 14.1 percent drop in USE for this material at 54 EFPY. Both the staff's and the applicant's percent drop in USE values are less than the maximum allowable 39.0 percent drop in USE criterion for BWR-3/6 non-Linde 80 weld materials given in BWRVIP-74A and confirm that the applicant's percent drop analysis for limiting circumferential weld FG is acceptable.

For the USE assessment of the Unit 1 RV plate materials, the staff determined that the limiting RV plate material is the lower intermediate shell plate fabricated from Heat No. B8946-1. This determination was found to be consistent with the limiting material identified by the applicant. The staff calculated a 21.0 percent drop for this material at 54 EFPY. This is based on use of a 1/4T neutron fluence of 0.291 x 10^{19} n/cm^2 (E > 1.0 MeV) at 54 EFPY. In comparison, the applicant calculated a 21.0 percent drop in USE for this material at 54 EFPY. Both the staff's and the applicant's percent drop in USE values are less than the maximum allowable 23.5 percent drop in USE criterion for BWR/3-6 plate materials given BWRVIP-74-A and confirm that the applicant's percent drop analysis for the limiting lower intermediate shell plate is acceptable.

For the USE assessment of the Unit 2 RV weld materials, the staff determined that the limiting RV weld material is circumferential weld FG (Heat No. S3986). This determination was found to be consistent with the limiting material identified by the applicant. The staff calculated a 13.5 percent drop for this material at 54 EFPY. This is based on use of a 1/4T neutron fluence of 0.235 x 10^{19} n/cm^2 (E > 1.0 MeV) at 54 EFPY. In comparison, the applicant calculated a 13.3 percent drop in USE for this material at 54 EFPY. Both the staff's and the applicant's percent drop in USE values are less than the maximum allowable 39.0 percent drop in USE criterion for BWR-3/6 non-Linde 80 weld materials given in BWRVIP-74-A and confirm that the applicant's percent drop analysis for limiting circumferential weld FG is acceptable.

For the USE assessment of the Unit 2 RV plate materials, the staff determined that the RV is limited by the lower shell plate made from Heat No. C4500-2. This determination was found to be consistent with the limiting material identified by the applicant. The staff calculated a 17.1 percent drop for this material at 54 EFPY. This is based on use of a 1/4T neutron fluence of 0.235 x 10^{19} n/cm^2 (E > 1.0 MeV) at 54 EFPY. In comparison, the applicant calculated a 17.0 percent drop in USE for this material at 54 EFPY. Both the staff's and the applicant's percent drop in USE values are less than the maximum allowable 23.5 percent drop criterion for BWR/3-6 plate materials given in BWRVIP-74-A and confirm that the applicant's percent drop analysis for the limiting lower shell plate is acceptable.

Based on these assessments, the staff found that the applicant had demonstrated that the percent drop in USE values for the BSEP plate materials at 54 EFPY remain bounded by the maximum 23.5 percent drop in USE approved by the NRC for BWR-3/6 plate materials and that the percent drop in USE values for the BSEP weld materials at 54 EFPY remain bounded by the maximum 39 percent drop in USE value approved by the staff for non-Linde 80 BWR-2/6 submerged arc weld materials. The staff, therefore, found that the applicant has satisfied Renewal Applicant Action Item 10 and that the TLAA on USE/EMA for the BSEP RV plate and weld materials is acceptable, as evaluated in accordance with the criterion of 10 CFR 54.21(c)(1)(i).

Technical Evaluation on the USE / EMA Analysis for the BSEP N16 Nozzles

In LRA Table 4.2-5 for Unit 1 and LRA Table 4.2-6 for Unit 2, the applicant projected that the limiting neutron fluence for the BSEP N!16 instrumentation nozzle forgings at the inside surface (ID) of the RV will be 1.38 x 10^{18} n/cm^2 (E > 1.0 MeV) at 54 EFPY. The applicant therefore concluded that the EMA for the N!16 instrumentation nozzles remains valid for the period of extended operation and is acceptable in accordance with 10 CFR 54.21(c)(1)(i). In SER Section 4.2.1, the staff concluded that the applicant had provided an acceptable basis concluding that the ID neutron fluence of 1.38 x 10^{18} n/cm^2 (E > 1.0 MeV) for the N!16 instrumentation nozzle forgings is acceptable for 54 EFPY. In the staff's October 16, 1998, SE on the applicant's USE and EMA assessment for the BSEP N!16 instrumentation nozzle forgings, the staff independently projected that the N!16 instrumentation nozzle forgings would have acceptable safety margins on USE down to a minimum value of 30 ft-lb. The staff, therefore, concluded that the applicant had provided an acceptable basis for establishing 70 ft-lb as the UUSE value for the components; and 57.4 ft-lb was an acceptable value at EOL (32 EFPY), as based on a conservative neutron fluence estimate of 1.6 x 10^{18} n/cm^2 (E > 1.0 MeV). Since the staff approved the limiting 54 EFPY fluence value for the N!16 instrumentation nozzle forgings in SER Section 4.2.1, and since this fluence value is bounded by the ID neutron fluence value used in the NRC-approved USE/EMA assessment for the nozzles (i.e., bounded by a fluence of 1.6 x 10^{18} n/cm^2 [E > 1.0 MeV]), the staff found that the projected USE value for the BSEP N!16 instrumentation nozzle forgings at 54 EFPY will remain bounded by a USE value of 57.4 ft-lb. Based on this assessment, the applicant's TLAA on USE/EMA for the N!16 instrumentation nozzle forgings meets the criterion of 10 CFR 54.21(c)(1)(i) and remains valid for the period of extended operation.

The staff's SE of October 16, 1998, only pertains to a plant-specific EMA for the N!16 instrumentation nozzle forgings and did not include evaluation of an EMA for the BSEP N!16 instrumentation nozzle welds. However, the generic EMA in NRC-approved Topical Report BWRVIP-74-A, as assessed for welds fabricated using a shielded metal arc welding (SMAW) process, is applicable to the USE evaluation of the BSEP N!16 instrumentation nozzle welds. In its response to RAI 4.2-1, dated May 4, 2005, which was discussed in SER Section 4.2, above, the applicant indicated that USE/EMA assessment for the N!16 instrumentation nozzle welds are bounded by the limiting RV beltline weld materials for USE at 54 EFPY.

The applicant provided its Certified Material Test Reports (CMTRs) for the BSEP N!16 instrumentation nozzle welds in CP&L Serial Letter No. BSEP-94-0316, dated August 17, 1994. The CMTRs reported the heat of material for the Unit 1 N!16 instrumentation nozzle weld to be Heat No. 650X006 and the heat of material for the Unit 2 N!16 instrumentation nozzle weld to be Heat No. 601221. The CMTRs confirmed that the BSEP N!16 instrumentation nozzle welds were fabricated using SMAW processes.

The applicant also identified that the weight percent of copper (wt.-% Cu) value for the BSEP N!16 instrumentation nozzle welds is limited by the value of 0.060 wt.-% Cu, as reported by the applicant's most recent license amendment request for the BSEP P-T limits in CP&L Serial Letter No. BSEP 96-344, dated January 7, 1997.

The staff performed an independent calculation of the 54 EFPY USE value for the BSEP N!16 instrumentation nozzle welds. The staff based its independent assessment on the generic equivalent margins analysis in NRC-approved topical report BWRVIP-74-A, as applied, for welds fabricated from SMAW processes. The staff also based its calculation on the limiting 54 EFPY 1/4T neutron fluence and limiting wt.-% Cu value for the N!16 instrumentation nozzle welds. For the BSEP N!16 instrumentation nozzle welds, the staff independently calculated that the percent drop in USE for the materials would be no greater than 12.0 percent, as projected to 54 EFPY. This percent drop value is bounded by the maximum allowable percent drop of 35 percent for SMAW-fabricated welds, as approved by the staff in BWRVIP-74-A. Therefore, the applicant's response to RAI 4.2.1-1 is valid and is resolved with respect to confirming that the 54 EFPY USE value for the BSEP N!16 instrumentation nozzle welds remains bounded by the applicable generic equivalent margins analysis approved in BWRVIP-74-A. Based on this independent assessment, the staff found that the USE/EMA analysis for the BSEP N!16 instrumentation nozzle welds has been acceptably projected out to the expiration of the extended period of operation and is acceptable pursuant to 10 CFR 54.21(c)(1)(ii). Therefore, RAI 4.2-1 is resolved with respect to the USE/EMA analysis for these welds.

4.2.2.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the TLAA on USE/EMA in LRA Section A.4.1.2.1.1:

> A.1.2.1.1 Upper Shelf Energy Evaluation
>
> Upper-shelf energy (USE) is the standard industry parameter used to indicate the maximum toughness of a material at high temperature. However, the Charpy tests performed on BSEP reactor pressure vessel (RPV) materials under the code of record provided limited Charpy impact data. It was not possible to develop original Charpy impact test USE values using methods invoked by 10 CFR 50, Appendix G. Therefore, BSEP was required to demonstrate that lower values of USE will provide margins of safety against fracture equivalent to those required.
>
> For plates and welds, end-of-life fracture energy was evaluated during the current license period by using the equivalent margin analysis (EMA) methodology described in NEDO-32205-A. This methodology was approved by the NRC as documented in a letter from the BWR Owners' Group (L. England) to the NRC (D. McDonald), dated March 24, 1994, "BWR Owners' Group Topical Report on Upper Shelf Energy Equivalent Margin Analysis – Approved Version", BWROG-94037, (Accession No. 94038280161). This analysis confirmed that an adequate margin of safety against fracture, equivalent to 10 CFR 50, Appendix G requirements, does exist. The USE values for BSEP materials were evaluated by an EMA using the 54 EFPY calculated fluence and BSEP surveillance capsule results. The results are also compared to the limits from BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," June, 2003, which has been approved by the NRC for use in License Renewal reviews. The results show that the limiting Charpy USE EMA percent reduction is less than the BWRVIP-74-A acceptance criteria in all cases.
>
> Therefore, a 60-year USE EMA for BSEP plates and welds has been prepared using a methodology previously reviewed and approved by the NRC, and the results meet the applicable acceptance criteria in all cases. Thus, the USE values for plates and welds have been satisfactorily projected

through the end of the period of extended operation. In its response to Generic Letter 92-01, Revision 1, Supplement 1, dated November 16, 1995, BSEP committed to provide a plant-specific USE EMA for reactor pressure vessel N16 forged nozzles. Each reactor vessel contains two, 2-inch nominal pipe size forged instrument nozzles, N16A and N16B, within the upper beltline region. BSEP performed a plant-specific EMA as required by 10 CFR 50, Appendix G. The analysis showed that the N16 nozzles for both reactor vessels should have had an initial, unirradiated USE (UUSE) of at least 70 ft-lbs. In addition, the USE was not anticipated to drop more than 18% for either reactor vessel, based upon a conservative projection of the end-of-life fluence. Therefore, the end-of-life USE of the nozzles for both vessels was anticipated to remain higher than the minimum screening criterion of 50 ft-lbs.

For added conservatism, an EMA was also performed per the guidelines provided in USNRC Regulatory Guide 1.161. This analysis demonstrated that the N16 nozzles would meet the ASME Code, Section XI, Appendix K, and Regulatory Guide 1.161 J-R fracture toughness requirements with an end-of-life USE as low as 29 ft-lbs. It was also shown that a 29 ft-lb end-of-life USE value would be equivalent to an initial USE of 35 ft-lbs, conservatively assuming the 18% drop in USE over the life of the vessels. As noted above, it has been shown that the subject nozzle material should have an initial USE of at least 70 ft-lbs. In a Safety Evaluation dated October 16, 1998, the NRC staff concluded that the BSEP EMA for the nozzle forgings is sufficiently conservative and, therefore, is acceptable.

For License Renewal, the EMA has been reviewed using the predicted neutron fluence for 60 years of operation. The predicted 60-year fluence for the N16 nozzles is below the value used in the EMA that has previously been reviewed and approved by the NRC. Therefore, the USE equivalent margins analysis for the N16 nozzle forgings has been demonstrated to remain valid for the period of extended operation.

The applicant's UFSAR supplement summary description for the TLAA on USE/EMA provides sufficient details of how the TLAA of USE/EMA on the RV beltline plate and weld materials has been projected through the expiration of the extended period of operation and why the TLAA is in compliance with 10 CFR 54.21(c)(1)(ii) and the NRC's USE/EMA safety margin requirements of 10 CFR Part, 50, Appendix G, as projected through the expiration of the period of extended operation. The staff, therefore, found that the TLAA on USE/EMA of the beltline plate and weld materials is acceptable and complies with 10 CFR 54.21(d).

The applicant's UFSAR supplement summary description for the TLAA on USE/EMA also provides a sufficient basis for demonstrating why the applicant's previous analysis on USE/EMA of the RV N!16 instrumentation nozzles remains in compliance with the NRC's USE/EMA safety margin requirements of 10 CFR Part, 50, Appendix G, and thus why the TLAA remains valid in accordance with 10 CFR 54.21(c)(1)(i) for the period of extended operation for BSEP. The staff, therefore, found that the TLAA on USE/EMA of the BSEP RV N!16 instrumentation nozzles is acceptable and complies with 10 CFR 54.21(d).

4.2.2.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the USE/EMA analyses for BSEP RV beltline plate and weld materials TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the USE/EMA analyses for BSEP RV beltline plate and weld materials TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the USE/EMA analyses for BSEP RV N-16 instrumentation nozzles TLAA, (i) the analyses remain valid for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the USE/EMA analyses for BSEP RV N-16 instrumentation nozzles TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.3 Adjusted Reference Temperature Analysis

In LRA Section 4.2.3, the applicant concluded that the calculations of the 1/4T RT_{NDT} values for the RV beltline materials is a TLAA, as defined in 10 CFR 54.3. Henceforth, this TLAA will be referred to as the "TLAA on 1/4T RT_{NDT} values."

4.2.3.1 Technical Information in the Application

The applicant provided the following assessment for the TLAA on 1/4T RT_{NDT} values in LRA Section 4.2.3:

> **4.2.3 ADJUSTED REFERENCE TEMPERATURE (ART) ANALYSIS**
>
> 10 CFR 50, Appendix G specifies fracture toughness requirements for ferritic materials of pressure-retaining components within the beltline region of the reactor coolant pressure boundary. This provides adequate margins of safety during any condition of normal operation to which the pressure boundary may be subjected over its service lifetime, including anticipated operational occurrences and system hydrostatic tests. The requirements of Appendix G apply to the reactor vessel beltline materials. For each BSEP unit, the N16 nozzle forgings are included within the beltline region. The adjusted reference temperature (ART) must account for the effects of neutron irradiation for the expected lifetime of the plant.
>
> 10 CFR 50 Appendix G requires the initial unirradiated nil ductility temperature, $RT_{NDT(U)}$ to be evaluated according to the procedures in ASME Section III, Paragraph NB-2331, which require drop-weight testing. However, many older plants, BSEP among them, were built while the ASME Code requirements were still evolving. For BSEP, not all of the tests required to determine the initial unirradiated RT_{NDT} per the present version of the Code were performed. Therefore, estimation methods were developed which could be used to determine the initial $RT_{NDT(U)}$ using the available test data in the same terms as the new requirements. The BSEP response to Generic Letter 92-01, Revision 1, Supplement 1, indicated the following estimation methods that were used to determine initial RT_{NDT} values for BSEP beltline materials: (1) Branch Technical Position MTEB 5-2, Estimation Method No. 4, (2) General Electric estimation procedure, and (3) the testing of archive material.
>
> **Analysis**
>
> The BSEP reactor vessels were designed for a 40-year life with an assumed neutron exposure of less than 1.0E+19 n/cm^2 from energies exceeding 1.0 MeV. The current licensing basis calculations use realistic calculated fluence values that are lower than this limiting value. The design basis value of 1.0E+19 n/cm^2 bounds calculated fluence values for the original 40-year term for both units.
>
> For License Renewal, the 54 EFPY fluence values at the ¼T location have been used to determine the 60-year ART values for each beltline material, as shown in Table 4.2-5 for Unit 1, and in Table 4.2-6 for Unit 2. The same initial nil-ductility transition temperatures submitted in the BSEP response to Generic Letter 92-01, Revision 1, Supplement 1, were used in the License Renewal ART calculations, except that a new value was estimated for the Girth Weld FG using the General Electric estimation method. The 60-year ART value was computed by determining the initial $RT_{NDT(U)}$ for the unirradiated material and then determining the shift due to irradiation effects,)RT_{NDT}, which is added to the initial value. A margin term is added to account for uncertainties, resulting in the upper bound value for ART.
>
> The ART analyses for BSEP Unit 1 and Unit 2 have been projected to the end of the period of extended operation using Method (ii) from 10 CFR 54.21(c)(1). The 60-year ART values for BSEP Unit 1 and Unit 2 were determined, and the results for the limiting component (highest ART value) in each unit are shown below, along with the corresponding inside surface fluence and 1/4T fluence. The

ART values were used in Subsection 4.2.4 to determine Operating Pressure-Temperature Limits for the RPV.

Parameter	Unit 1 Limiting Material	Unit 2 Limiting Material
	Plate B8496-1	N16 Nozzle Forging Heat Q2Q1VW
Inside Surface Fluence (n/cm^2) (E > 1.0 MeV)	4.00E18	1.38E18
1/4T Fluence (n/cm^2) (E > 1.0 MeV)	2.86E18	0.99E18
1/4T ART (EF)	136.1	125.1

Disposition: 10 CFR 54.21(c)(1)(ii) – The ART analyses have been projected to the end of the period of extended operation.

The applicant provided its calculations of the 1/4T RT_{NDT} values for 54 EFPY in LRA Table 4.2-5 for the Unit 1 RV beltline materials and in LRA Table 4.2-6 for the Unit 2 RV beltline materials.

4.2.3.2 Staff Evaluation

Regulatory Evaluation. The 1/4T RT_{NDT} values for the RV beltline materials are used as part of the inputs to the P-T limit curve calculations, which are required by 10 CFR Part 50, Appendix G, for operating reactors. These 1/4T RT_{NDT} values are calculated in accordance with the NRC's recommended methodology of RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988. RG 1.99, Revision 2 may be accessed through the NRC Accession No. ML003740284.

The fracture toughness requirements of 10 CFR Part 50, Appendix G (including requirements for USE and for P-T limits), apply to all "ferritic materials of pressure-retaining components of the reactor coolant pressure boundary of light-water reactors to provide adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service life." The Rule requires that the values of USE and RT_{NDT} that are calculated in accordance with the Rule's requirements must account for the effects of neutron radiation, including the impacts of implementation of the plant's RV surveillance program that is implemented in accordance with the requirements of 10 CFR Part 50, Appendix H. For ferritic components in the RCPB, the changes in fracture toughness properties resulting from neutron radiation are bounded by those that occur in the ferritic materials located in the beltline region of the RV.

Technical Evaluation. The staff performed independent calculations of the 1/4T RT_{NDT} values for the BSEP RV beltline materials through 54 EFPY. The staff applied the calculation methods of RG 1.99, Revision 2, as the basis for its independent calculations. The staff also applied the 1/4T neutron fluences for materials as the basis for its independent calculations. These fluences are listed in Table 4.1.2 of the LRA for 54 EFPY of power operation. The staff's basis for accepting the applicant's 1/4T neutron fluences for 54 EFPY is given in SER Section 4.1.2.2.

The staff also determined that the BWRVIP's ISP is applicable for monitoring the changes in fracture toughness for the BSEP RVs. However, since the surveillance materials in the ISP, which represent the BSEP RV limiting materials, are not a heat-to-heat match, the ISP surveillance capsule test materials are not used directly to calculate the changes in RT_{NDT}. The staff, therefore, determined that it was appropriate to apply the Chemistry Factor (CF) tables in RG 1.99, Revision 2 as the basis for determining the CF values used in the 1/4T RT_{NDT} calculations for BSEP. This is consistent with the recommended methodology of Position 1.1 of RG 1.99, Revision 2.

For Unit 1, the staff confirmed that the lower intermediate shell plate fabricated from Heat No. B8496-1 was the limiting 1/4T RT_{NDT} component in the RV. The staff calculated a limiting 1/4T RT_{NDT} value of 136.5 EF for this plate material, as based on use of the CF table for plate/forging materials in RG 1.99, Revision 2, and use of an NRC-approved 1/4T fluence of 0.291 x 10^{19} n/cm^2 (E > 1.0 MeV) at 54 EFPY. The 1/4T RT_{NDT} value calculated by the staff at 54 EFPY is within 0.4 EF of the 1/4T RT_{NDT} value calculated by the applicant for this material (i.e., 136.1 EF at 54 EFPY by the applicant's calculation). Since the staff's independent 1/4T RT_{NDT} value is in excellent agreement with the value calculated by the applicant, the staff found that the applicant had calculated and projected a valid limiting 1/4T RT_{NDT} value for the Unit 1 RV at 54 EFPY, and that the TLAA on 1/4T RT_{NDT} values for Unit 1 is acceptable, as evaluated in accordance with the criterion of 10 CFR 54.21(c)(1)(ii).

For Unit 2, the staff confirmed that the N!16 A and B instrumentation nozzle forgings (Heat No. Q2Q1VW) were the limiting 1/4T RT_{NDT} components in the RV. The staff calculated a limiting 1/4T RT_{NDT} value of 125.6 EF for this forging material, as based on use of the CF table for plate/forging materials in RG 1.99, Revision 2, and use of a staff approved 1/4T fluence of 0.101 x 10^{19} n/cm^2 (E > 1.0 MeV) at 54 EFPY. The 1/4T RT_{NDT} value calculated by the staff at 54 EFPY is within 0.5 EF of the 1/4T RT_{NDT} value calculated by the applicant for this material (i.e., 125.1 EF at 54 EFPY by the applicant's calculation). Since the staff's independent 1/4T RT_{NDT} value is in excellent agreement with the value calculated by the applicant, the staff found that the applicant had calculated and projected a valid limiting 1/4T RT_{NDT} value for the Unit 2 RV at 54 EFPY, and that the TLAA on 1/4T RT_{NDT} values for Unit 2 is acceptable, as evaluated in accordance with the criterion of 10 CFR 54.21(c)(1)(ii).

In the applicant's response to RAI 4.2-1, dated May 4, 2005, the applicant indicated that the 54 EFPY 1/4T RT_{NDT} values for the BSEP N!16 instrumentation nozzle welds are bounded by those for the limiting 1/4T RT_{NDT} materials located in the beltline regions of the BSEP RV shells.

To assess the validity of the applicant's response to RAI 4.2-1, the staff performed independent calculations of the 1/4T RT_{NDT} values for the BSEP N!16 instrumentation nozzle welds, as projected using the 54 EFPY 1/4T neutron fluences (in units of n/cm^2, E > 1.0 MeV) for the materials. The limiting 54 EFPY 1/4T neutron fluence for the N!16 instrumentation nozzle welds is equivalent to that projected for the BSEP N!16 instrumentation nozzle forgings at 54 EPFY, which is 0.101 x 10^{19} n/cm^2 (E > 1.0 MeV).

The applicant provided its CMTR for the BSEP N!16 instrumentation nozzle welds in CP&L Serial Letter No. BSEP-94-0316, dated August 17, 2004. The CMTRs reported the heat of material for the Unit 1 N!16 instrumentation nozzle weld to be Heat No. 650X006 and the heat of material for the Unit 2 N!16 instrumentation nozzle weld to be Heat No. 601221. The CMTRs also confirm that the BSEP N!16 instrumentation nozzle welds were fabricated using SMAW processes.

The applicant also provided the wt.-% copper and nickel values for the BSEP N!16 instrumentation nozzle welds in its most recent P-T limit license amendment request for BSEP, in CP&L Serial Letter No. BSEP 96-0344, dated January 7, 1997. In this submittal, the applicant reported 10EF as the initial RT_{NDT} value for these materials. The applicant also reported the following wt.-% of Cu and nickel (Ni) for these materials:

- Unit 1 N!16 instrumentation nozzle weld ! wt.-% Cu: 0.060; wt.-% Ni: 0.870
- Unit 2 N!16 instrumentation nozzle weld ! wt.-% Cu: 0.030; wt.-% Ni: 0.880

For its calculations, the staff used Table 1 in RG 1.99, Revision 2 to determine the CFs for the BSEP N!16 instrumentation nozzle welds, as based on the wt.-% Cu and Ni values for the materials. The staff then applied these CFs and the 54 EFPY 1/4T neutron fluences for the welds to the 1/4T RT_{NDT} calculations. The staff also applied a full margin term to the calculations.

The staff calculated a limiting 54 EFPY 1/4T RT_{NDT} value of 70.2EF for the Unit 1 N!16 instrumentation nozzle weld. This is bounded by the limiting 54 EFPY 1/4T RT_{NDT} value of 136.5EF for the Unit 1 lower intermediate shell plate fabricated from plate heat No. B8496-1. The staff calculated a limiting 54 EFPY 1/4T RT_{NDT} value of 23.2EF for the Unit 2 N!16 instrumentation nozzle weld. This is bounded by the limiting 54 EFPY 1/4T RT_{NDT} value of 125.6EF for the Unit 2 N!16 instrumentation nozzle forging fabricated from Heat No. Q2Q1VW. Based on these independent calculations, the staff found 54 EFPY 1/4T RT_{NDT} value calculations for BSEP N!16 instrumentation nozzle welds are bounded by the 1/4T RT_{NDT} values for the limiting RV beltline shell materials at 54 EFPY. Therefore, the applicant's response to RAI 4.2.1-1 is valid and is resolved with respect to confirming that the 1/4T RT_{NDT} values for the N!16 instrumentation nozzle welds are acceptable for 54 EFPY. Based on this independent assessment, the staff found that the 1/4T RT_{NDT} values for the BSEP N!16 instrumentation nozzle welds have been projected to 54 EFPY and are acceptable pursuant to 10 CFR 54.21(c)(1)(ii). RAI 4.2-1 is resolved with respect to the 1/4T RT_{NDT} analysis for the BSEP N!16 instrumentation nozzle welds.

4.2.3.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the applicant's TLAA on 1/4T RT_{NDT} values:

> A.1.2.1.2 Adjusted Reference Temperature Analysis
>
> The BSEP reactor vessels were designed for a 40-year life with an assumed neutron exposure of less than 1.0E+19 n/cm2 from energies exceeding 1.0 MeV. The CLB calculations use realistic calculated fluence values that are lower than this limiting value.
>
> The design basis value of 1.0E+19 n/cm2 bounds calculated fluence values for the original 40-year term for both units. For License Renewal, the 54 EFPY fluence values at the 1/4T location have been used to determine the 60-year Adjusted Reference Temperature (ART) values for each beltline material for Unit 1 and Unit 2. The same initial nil-ductility transition temperatures submitted in the BSEP response to Generic Letter 92-05, Revision 1, Supplement 1, were used in the License Renewal ART calculations, except that a new value was estimated for Girth Weld FG using the General Electric estimation method. The 60-year ART value was computed by determining the initial $RT_{NDT(U)}$ for the unirradiated material and then determining the shift due to irradiation effects,)RT_{NDT},

which is added to the initial value. A margin term is added to account for uncertainties, resulting in the upper bound value for ART.

The ART analyses for BSEP Unit 1 and Unit 2 have been projected to the end of the period of extended operation. The values for BSEP Unit 1 and Unit 2 for the limiting component (highest ART value) in each unit are shown below, along with the corresponding inside surface fluence and 1/4T fluence. The ART values were used to determine Operating Pressure-Temperature Limits for the RPV.

Parameter	Unit 1 Limiting Material	Unit 2 Limiting Material
	Plate B8496-1	N16 Nozzle Forging Heat Q2Q1VW
Inside Surface Fluence (n/cm^2) (E > 1.0 MeV)	4.00E18	1.38E18
1/4T Fluence (n/cm^2) (E > 1.0 MeV)	2.86E18	0.99E18
1/4T ART (EF)	136.1	125.1

The applicant's UFSAR supplement summary description for the TLAA on 1/4T RT_{NDT} values provides a sufficient basis for demonstrating how the calculation of the limiting 1/4T RT_{NDT} values for BSEP RV beltline materials were projected through the expiration of the extended period of extended operation for BSEP (i.e., at 54 EFPY) and why the TLAA is in compliance with the staff's criterion in 10 CFR 54.21(c)(1)(ii). The applicant's UFSAR supplement summary description for this TLAA is consistent with the staff's evaluation in SER Section 4.2.2.2 and is, therefore, acceptable and in compliance with 10 CFR 54.21(d).

4.2.3.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the ART analysis TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the ART analysis TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.4 RPV Operating Pressure-Temperature Limits

In LRA Section 4.2.4, the applicant indicated concluded that the calculations of the RV P-T limits for BSEP is a TLAA, as defined in 10 CFR 54.3. Henceforth, this TLAA will be referred to as the "TLAA on P-T Limits."

4.2.4.1 Technical Information in the Application

The applicant provided the following assessment for the TLAA on P-T limits in LRA Section 4.2.4:

> **4.2.4 RPV OPERATING PRESSURE-TEMPERATURE (P-T) LIMITS**
>
> **Summary Description**
>
> The Adjusted Reference Temperature (ART) is the value of Initial RT_{NDT} +) RT_{NDT} + margins for uncertainties at a specific location. Neutron embrittlement increases the ART. Thus, the minimum temperature at which a reactor vessel is allowed to be pressurized increases over the licensed period. The . . . [RT $_{NDT}$] . . . of the limiting beltline material is used to correct the beltline operating Pressure-Temperature (P-T) limits to account for irradiation effect. 10 CFR Part 50 Appendix G requires reactor vessel thermal limit analyses to determine operating pressure-temperature (P-T) limits for boltup, hydrotest, pressure tests and normal operating and anticipated operational occurrences. Operating limits for pressure and temperature are required for three categories of operation: 1) hydrostatic pressure tests and leak tests, . . . [2)] . . . non-nuclear heat-up/cooldown and low level physics tests, and . . . [3)] . . . core critical operation. The calculations associated with generation of the P-T curves satisfy the criteria of 10 CFR 54.3(a). As such, this topic is a TLAA.
>
> **Analysis**
>
> The BSEP Technical Specifications contain P-T limit curves for heatup, cooldown, and in-service leakage and hydrostatic testing and also limit the maximum rate of change of reactor coolant temperature. The criticality curves provide limits for both heat-up and criticality calculated for a 32 EFPY operating period. Because of the relationship between the P-T limits and the fracture toughness transition of the reactor vessel, BSEP will require new P-T limits to be calculated.
> P-T limit curves applicable for BSEP Units 1 and 2 for 60 years have been developed based upon the 54 EFPY fluence projections discussed in Subsection 4.2.1. These curves were developed to account for the increased fluence associated with the period of extended operation, and show that adequate operating margins will exist when they are used.
>
> **Disposition: 10 CFR 54.21(c)(1)(ii) – The P-T limit analyses have been projected to the end of the period of extended operation.**

4.2.4.2 Staff Evaluation

Regulatory Evaluation

Technical Specification Requirements

10 CFR 50.36, "Technical Specifications," requires licensees owning nuclear power production facilities to include P-T limits and low pressure/overpressure protection system setpoints (for pressurized water reactors (PWRs)) among the limiting conditions for operation (LCOs) in the plant TS.[1]

Additional Regulatory Guidance in the NRC SER on Topcial Report BWRIP-74, as Applicable to TLAAs on P-T Limits

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[1] Pressure-temperature limit reports (PTLRs) that are approved by the NRC pursuant to 10 CFR 50.90 license amendment requests for PTLRs are an exception to this statement. However, PTLRs have not been approved for the BSEP units. The 32 EFPY P-T limit curves for the facility are currently located in the limiting conditions for operation of the BSEP Technical Specifications. Thus, the exception is not applicable to the BSEP LRA and to evaluation of this TLAA.

On September 21, 1999, the BWRVIP submitted Topical Report TR-1113596, “BWRVIP-74: BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal,” (BWRVIP-74). In Section A.4.5 of this topical report, the BWRVIP provided its recommendations on which actions BWR applicants would have to take with respect to submitting TLAAs on P-T limits. The staff provided its FSER on BWRVIP-74 on October 18, 2001. In this FSER, the staff established the following position on TLAAs for BWR P-T limits:

> The staff evaluates the P-T limit curves based on the following NRC regulations and guidance: 10 CFR Part 50, Appendix G; GL 88-11; GL 92-01, Revision 1; GL 92-01, Revision 1, Supplement 1; Regulatory Guide (RG) 1.99, Revision 2 (Rev. 2); and Standard Review Plan (SRP) Section 5.3.2. GL 88-11 advised licensees that the staff would use RG 1.99, Rev. 2, to review P-T limit curves. RG 1.99, Rev. 2, contains methodologies for determining the increase in transition temperature and the decrease in Charpy USE resulting from neutron radiation. GL 92-01, Rev. 1, requested that licensees submit their RPV data for their plants to the staff for review. GL 92-01, Rev. 1, Supplement 1, requested that licensees provide and assess data from other licensees that could affect their RPV integrity evaluations. These data are used by the staff as the basis for the staff's review of P-T limit curves. Appendix G to 10 CFR Part 50 requires that P-T limit curves for the RPV be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Code.
>
> SRP Section 5.3.2 provides an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM) methodology of Appendix G to Section XI of the ASME Code. The basic parameter of this methodology is the stress intensity factor K_I, which is a function of the stress state and flaw configuration. Appendix G requires a safety factor of 2.0 on stress intensities resulting from reactor pressure during normal and transient operating conditions, and a safety factor of 1.5 for hydrostatic testing curves. The methods of Appendix G postulate the existence of a sharp surface flaw in the RPV that is normal to the direction of the maximum stress. This flaw is postulated to have a depth that is equal to 1/4-thickness (1/4T) of the RPV beltline thickness and a length equal to 1.5 times the RPV beltline thickness. The critical locations in the RPV beltline region for calculating heatup and cooldown P-T curves are the 1/4-thickness (1/4T) and 3/4-thickness (3/4-T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively.
>
> The Appendix G ASME Code methodology requires that licensees determine the adjusted reference temperature (ART or adjusted RT_{NDT}). The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin (M) term.
>
> The ΔRT_{NDT} is a product of a chemistry factor and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in RG 1.99, Rev. 2, or from surveillance data. The fluence factor is dependent upon the neutron fluence at the maximum postulated flaw depth. The margin term is dependent upon whether the initial RT_{NDT} is a

plant-specific or a generic value and whether the chemistry factor (CF) was determined using the tables in RG 1.99, Rev. 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence and the calculational procedures. RG 1.99, Rev. 2, describes the methodology to be used in calculating the margin term.

Appendix A to the BWRVIP-74 report identifies the regulatory requirements for P-T Limits. The report indicates that a set of P-T curves should be developed for the heatup and cooldown operating conditions in the plant at a given EFPY in the LR period. This is Renewal Applicant Action Item 9.

Technical Evaluation. The applicant has identified that the calculation of P-T limits is a TLAA for the LRA. The RT_{NDT} values for the 1/4T locations are critical input parameters into the calculation of the P-T limit curves for BSEP. Since the calculation of the P-T limits is impacted by the calculation of the limiting 1/4T RT_{NDT} values for the BSEP RVs, and since 32 EFPY P-T limit curves have been approved for BSEP, the staff agreed that the calculation of P-T limits is a TLAA for the BSEP facilities.

The staff approved 32 EFPY P-T limit curves for BSEP in License Amendment No. 228 for Unit 1 and License Amendment No. 256 for Unit 2. Thus, the 32 EFPY P-T limit curves for BSEP are currently included within the scope of the limiting conditions for operation for the BSEP TS and are a TLAA for the LRA.

Under the NRC’s current 10 CFR 50.90 license amendment process, the applicant is required to submit and to have new P-T limit curves approved by the staff prior to expiration of the P-T limit curves that are currently approved in the technical specifications. Pursuant to 10 CFR 54.35, this review process will carry over into the period of extended operation for BSEP. Therefore, the staff is not requiring the P-T limits for the extended period of operation to be submitted as part of staff’s review of the LRA. Instead, the staff will continue to require NRC approval of the P-T limit curves for the extended period of operation prior to expiration of the P-T limit curves for 32 EFPY.

The staff’s review of the P-T limit curves limits for the period of extended operation for BSEP, when submitted in accordance with the 10 CFR 50.90 license amendment process, will ensure that the operation of the reactors will be done in a manner that ensures the integrity of the reactor coolant system during the extended period of operation. When the BSEP P-T limit curves for the extended period of operation are submitted as a license amendment request, the staff’s evaluation of the new P-T limit curves will be based on compliance with the P-T limit curve acceptance criteria requirements of 10 CFR Part 50, Appendix G. This process satisfies conformance with Applicant Action Item No. 9 onin BWRVIP-74-A.

4.2.4.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the applicant’s TLAA on P-T limits:

A.1.2.1.3 RPV Operating Pressure-Temperature (P-T) Limits

The Adjusted Reference Temperature (ART) is the value of Initial RT_{NDT} + ΔRT_{NDT} + margins for uncertainties at a specific location. Neutron embrittlement increases the ART. Thus, the minimum temperature at which a reactor vessel is allowed to be pressurized increases over the licensed period. The ART of the limiting beltline material is used to correct the beltline operating P-T limits to account for irradiation effects. 10 CFR Part 50, Appendix G, requires reactor vessel thermal limit analyses to determine operating P-T limits for boltup, hydrotest, pressure tests, and normal operating and anticipated operational occurrences.

The BSEP Technical Specifications contain P-T limit curves for heatup, cooldown, and in-service leakage and hydrostatic testing and also limit the maximum rate of change of reactor coolant temperature. The normal operation core critical curves provide limits for both heat-up and criticality calculated for a 32 EFPY operating period. Because of the relationship between the P-T limits and the ART of the reactor vessel, BSEP requires new P-T limits for the period of extended operation.

P-T limit curves applicable for BSEP Units 1 and 2 for 60 years have been developed based upon 54 EFPY fluence projections. These curves were developed to account for the increased fluence associated with the period of extended operation, and show that adequate operating margins will exist when they are used.

In RAI 4.2.4-1, dated April 8, the staff noted that the UFSAR supplement summary description provides a sufficient basis for concluding that the P-T limits for BSEP are a TLAA for the facilities and for stating why the applicant has developed 54 EFPY P-T limit curves for the facilities. However, the summary description does not discuss the most important aspect of the NRC's review process for the P-T limit curves for the period of extended operation in that the curves are required to be submitted to the NRC in accordance with the NRC's 10 CFR 50.90 license amendment process and to be approved by the staff prior to the expiration of the 32 EFPY P-T limit curves that are currently located in LCOs of the BSEP Technical Specifications. Therefore, the staff requested that the applicant modify the UFSAR supplement summary description to state that this will be done.

In its response, dated May 4, 2005, the applicant stated:

RAI 4.2.4-1 Response

P-T limit curves for the BSEP Units 1 and 2 periods of extended operation will be submitted for NRC review and approval in accordance with the 10 CFR 50.90 license amendment process at least one year prior to expiration of the 32 EFPY P-T limit curves that are currently approved in the BSEP Technical Specifications. As mandated in 10 CFR Part 50, Appendix G, this is required to cover P-T limit curves for the extended operating periods during both normal operations of the reactor, including heatups and cooldowns of the reactor, critical operations of the reactor, and transient operating conditions, and RV pressure test conditions. LRA Appendix A, Section A.1.2.1.3 will be revised to include this commitment.

The applicant's response to RAI 4.2.4-1 indicated that the applicant is committed to submitting the P-T limits for BSEP that are applicable to the period of extended operation at least one year prior to the expiration of the currently licensed P-T limit curves for 32 EFPY. The P-T limit curves will include curves for both normal operations of the reactor, including curves for heatups and cooldowns of the reactors, core critical operations, transient operations, and curves for RV pressure test conditions. The applicant stated that this commitment will be reflected in the UFSAR supplement for this TLAA. The applicant's response and commitment is consistent with the requirements of 10 CFR Part 50, Appendix G, and with the NRC's 10 CFR 50.90 license amendment process, as relevant to updates of P-T limit curves that are currently licensed in the limiting conditions of operations of the BSEP TSs. Since the commitment and process described in the applicant's response to RAI 4.2.4-1 is consistent with these NRC requirements, the staff found that the applicant's UFSAR supplement summary description and commitment for the TLAA on P-T limits is acceptable. Therefore, the staff's concern described in RAI 4.2.4-1 is resolved.

In CP&L Serial Letter No. BSEP 05-0097, dated July 18, 2005, the applicant provided a supplemental response to RAI 4.2.4-1 in regard to the P-T limits for BSEP. In this response, the applicant clarified that an NRC-approved exemption from the requirements of 10 CFR Part 50, Appendix G, allowing the applicant to apply methods of ASME Code N-640 to the P-T limit calculations for BSEP, was approved in NRC safety evaluation dated May 21, 2001. The exemption was approved in accordance with 10 CFR 50.60(b) and the NRC's exemption criteria of 10 CFR 50.12. In the applicant's response, the applicant clarified that the exemption granted on May 21, 2001, was only applicable to the current operating periods for BSEP and that if the use of Code Case N-640 is desired for calculation of the P-T limits for the period of extended operation and an exemption is still necessary, the applicant will include the exemption request in the applicant's license amendment submittal of the new P-T limits for the period of extended operation. This has been incorporated as a revision of the applicant's commitment for LRA Section A.1.2.1.3, "RPV Operating Pressure-Temperature (P-T) Limits," and is acceptable.

4.2.4.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the RPV operating P-T limits TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the RPV operating P-T limits TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.5 RPV Circumferential Weld Examination Relief

In LRA Section 4.2.5, the applicant concluded that the calculation of the mean adjusted reference temperature values (mean RT_{NDT} values) for the RV beltline circumferential weld failure probability and relief request analyses is a TLAA as defined in 10 CFR 54.3. Henceforth this TLAA will be referred to as the "TLAA on Circumferential Weld Relief Requests."

4.2.5.1 Technical Information in the Application

The applicant provided the following assessment for the TLAA on circumferential weld relief requests in LRA Section 4.2.5:

> **4.2.5 RPV CIRCUMFERENTIAL WELD EXAMINATION RELIEF**
>
> **Summary Description**
>
> The Boiling Water Reactor Vessel and Internals Project (BWRVIP) submitted a report that proposed to reduce the scope of inspection of BWR RPV welds from essentially 100 percent of all RPV shell welds to examination of essentially 100 percent of the axial (longitudinal) welds and essentially none of the circumferential RPV shell welds, except at the intersection of the axial and circumferential welds, thereby including approximately 2-3 percent of the circumferential welds. The report provided proposals to revise ASME Code requirements for successive and additional examinations of circumferential welds, provided in paragraph IWB-2420(b) of Section XI of the ASME Code.

The NRC staff issued a Safety Evaluation Report by NRC letter (G. Lainas) to the BWRVIP (c. Terry), dated July 28, 1998: “Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925).” This evaluation concluded that the failure frequency of RPV circumferential welds in BWR reactors was sufficiently low to justify elimination of inservice inspection (ISI) of these welds. In addition, the evaluation concluded that BWRVIP proposals on successive and additional examinations of circumferential welds were acceptable. The evaluation indicated that examination of the circumferential welds shall be performed if axial weld examinations reveal an active, mechanistic mode of degradation. A supplemental Safety Evaluation Report was provided on March 7, 2000.

On November 10, 1998, the NRC issued Generic Letter 98-05, “Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on RPV Shell Welds.” GL 98-05 stated that BWR licensees may request permanent relief (for the remaining term of operation under the existing license) from ISI requirements of 10 CFR 50.55a(g) for the volumetric examination of circumferential RPV welds (ASME Code Section XI, Table IWB-2500-1, Examination Category B-A, Item 1.11, “Circumferential Shell Welds”), upon demonstrating that:

1. the limiting conditional failure probability for circumferential welds satisfies the values specified in the NRC staff’s July 28, 1998, Safety Evaluation Report; and

2. licensees have implemented operator training and established procedures that limit the frequency of cold over-pressure events to the amount specified in the NRC staff’s July 28, 1998, Safety Evaluation Report.

Licensees would still need to perform the required inspections of “essentially 100 percent” of all axial welds.

BSEP submitted a request for relief and has received this relief for the remaining licensed operating period. T he circumferential weld examination relief analysis meets the requirements of 10 CFR 54.3(a) and is a TLAA.

Analysis

The NRC evaluation of BWRVIP-05 utilized a probabilistic fracture mechanics (PFM) analysis to estimate the RPV shell weld failure probabilities. Three key assumptions of the PFM analysis are:

1. the neutron fluence was the estimated end-of-life mean fluence
2. the chemistry values are mean values based on vessel types, and
3. the potential for beyond-design-basis events is considered.

Table 4.2-7 provides a comparison of the BSEP Units 1 and 2 reactor vessel limiting circumferential weld parameters to those used in the NRC evaluation for the first two key assumptions. Data provided in Table 4.2-7 was supplied from Tables 2.6-4 and 2.6-5 of the previously identified, July 28, 1998 NRC Safety Evaluation Report. However, the correction of the Chemistry Factor in the table is from the supplement to the SER issued by the NRC on March 7, 2000.

The 54 EFPY fluence values for BSEP are bounded by both the 32 EFPY and 64 EFPY fluence values in the NRC analysis. The BSEP Units 1 and 2 weld materials have lower copper and nickel values than those used in the NRC analysis. Hence, there is a smaller chemistry factor. As a result, the shifts in reference temperature for Units 1 and 2 are lower than both the 32 EFPY and 64 EFPY shift from the NRC SER analysis. The combination of unirradiated reference temperature ($RT_{NDT(U)}$) and shift (RT_{NDT}) yields adjusted reference temperatures for Units 1 and 2 that are considerably lower than the NRC mean analysis values. Therefore, the RPV shell weld embrittlement due to the additional fluence associated with the period of extended operation has a negligible effect on the probabilities of RPV shell weld failure. The Mean RT_{NDT} values for Units 1 and 2 at 54 EFPY are bounded by the 32 EFPY and the 64 EFPY Mean RT_{NDT} provided by the NRC.

Although a conditional failure probability has not been calculated, the fact that the BSEP values for Mean RT_{NDT} at the end of the 60-year license are less than both the 32 EFPY and 64 EFPY values provided by the NRC leads to the conclusion that the BSEP RPV conditional failure probability is bounded by the NRC analysis. Therefore, the TLAA has been projected through the end of the period of extended operation.

The procedures and training used to limit cold over-pressure events during the period of extended operation will be the same as those approved by the NRC when BSEP requested that the BWRVIP-05 technical alternative be used for the current licensing term for Units 1 and 2.

Disposition: 10 CFR 54.21(c)(1)(ii) – The RPV circumferential weld analyses have been projected to the end of the period of extended operation.

4.2.5.2 Staff Evaluation

Regulatory Evaluation.

Inservice Inspection Requirements

Inservice inspection of ASME Boiler and Pressure Vessel Code (ASME Code) Class 1, 2, and 3 components is performed in accordance with Section XI of the ASME Code and applicable addenda as required by 10 CFR 50.55a(g), except where specific relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i). Part 50.55a(a)(3) of 10 CFR states that alternatives to the requirements of paragraph (g) may be used, when authorized by the NRC, if: (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

Pursuant to 10 CFR 50.55a(g)(4), ASME Code Class 1, 2, and 3 components (including supports) shall meet the requirements, except the design and access provisions and pre-service examination requirements, set forth in the ASME Code, Section XI, "Rules for Inservice Inspection [ISI] of Nuclear Power Plant Components," (ASME Code, Section XI) to the extent practical within the limitations of design, geometry, and materials of construction of the components. The regulations require that ISI of components and system pressure tests conducted during the first ten-year interval and subsequent intervals comply with the requirements in the latest edition and addenda of the ASME Code, Section XI incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the 120-month interval, subject to the limitations and modifications listed therein. The current ISI Code of record for BSEP is the 1989 Edition of the ASME Code, Section XI, without supplement by applicable Code Addenda.

Augmented Inservice Inspection Requirements for RV Shell Welds

Section 50.55a(g)(6)(ii)(A)(2) of 10 CFR requires licensees to augment their RV examinations by implementing, as part of the ISI interval in effect on September 8, 1992, the examination requirements for reactor vessel shell welds specified in Item B1.10, Section XI, Table IWB-2500-1, Examination Category B-A, “Pressure Retaining Welds in Reactor Vessel.” Section XI, Item B1.10, includes the volumetric examination requirements for both circumferential RV shell welds, as specified in Section XI, Item B1.11, and longitudinal RV shell welds, as specified in Section XI, Item B1.12. 10 CFR 50.55a(g)(6)(ii)(A)(2) defines "essentially 100% examination” as covering 90 percent or more of the examination volume of each weld.

Additional Regulatory Guidance on the NRC’s Safety Evaluation (SE) of the BWRVIP-05 Report

By letter dated September 28, 1995, as supplemented by letters dated June 24 and October 29, 1996, May 16, June 4, June 13, and December 18, 1997, and January 13, 1998; the BWRVIP, a technical committee of the BWR Owners Group (BWROG), submitted the proprietary report, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations (BWRVIP-05)." The BWRVIP-05 report evaluates the current inspection requirements for RV shell welds in BWRs, formulates recommendations for alternative inspection requirements, and provides a technical basis for the recommended alternative inspection requirements. As modified, BWRVIP-05 proposed to reduce the scope of inspection of BWR RV welds from essentially 100 percent of all RV shell welds to examination of 100 percent of the axial welds and essentially zero percent of the circumferential RV shell welds, except for locations where the axial and circumferential welds intersect. In addition, the report includes proposed alternatives to ASME Code requirements for successive and additional examinations of circumferential welds, as provided in paragraph IWB-2420 and IWB-2430 respectively, of ASME Code Section XI.

In the BWRVIP-05 report, the BWRVIP committee concluded that the conditional probabilities of failure for BWR RV circumferential welds are orders of magnitude lower than those of the axial welds. As a part of its review of the report, the NRC conducted an independent probabilistic fracture mechanics assessment of the results presented in the BWRVIP-05 report. The staff's assessment conservatively calculated the conditional probability of failure values for RV axial and circumferential welds during the initial (current) 40-year license period and at conditions approximating an 80-year vessel lifetime for a BWR nuclear plant. The failure frequency is calculated as the product of the frequency for the critical (limiting) transient event and the conditional probability of failure for the weld. The staff determined the conditional probability of failure for axial and circumferential welds in BWR vessels fabricated by Chicago Bridge and Iron (CB&I), Combustion Engineering (CE), and Babcock and Wilcox (B&W). The analysis identified a cold overpressure event that occurred in a foreign reactor as the limiting event for BWR RVs, with the pressure and temperature from this event used in the probabilistic fracture mechanics calculations. The staff estimated that the probability for the occurrence of the limiting overpressurization transient was 1×10^{-3} per reactor year.

On July 28, 1998, the staff issued its FSER on BWRVIP-05. This evaluation concluded that the failure frequency of RV circumferential welds in BWRs was sufficiently low to justify elimination of ISI of these welds. In addition, the evaluation concluded that the BWRVIP proposals on successive and additional examinations of circumferential welds were acceptable. The evaluation indicated that examination of the circumferential welds will be performed if axial weld examinations reveal an active degradation mechanism. For each of the vessel fabricators, Table 2.6-4 of the staff's FSER of March 7, 2000, identifies the conditional failure probabilities for the plant-specific conditions with the highest projected mean adjusted reference temperature for each weld type proposed by the respective fabricator (i.e, mean RT_{NDT} calculations for each of the CB&I, CE, and B&W limiting axial weld and limiting circumferential weld case studies) through the expiration of the initial 40-year license period (32 EFPY) for a BWR-designed nuclear power plant using an 80 percent capacity factor. Table 2.6-5 of staff's FSER of July 28, 1998, identifies the conditional failure probabilities for the plant-specific conditions with the highest projected mean RT_{NDT} calculations for each of these case studies through the expiration of an 80-year license period, which constitutes the licensing basis if two 20-year extended periods of operation have been granted for a BWR-designed nuclear power plant using an 80 percent capacity factor (i.e., through 64 EFPY).

The staff amended this FSER in a supplemental FSER to the BWRVIP which is provided in a letter to Carl Terry, BWRVIP Chairman, dated March 7, 2000. In this supplemental FSER, the staff updated the interim probabilistic failure frequencies for RV axial shell welds and revised Table 2.6-4 to correct a typographical error in the 32 EFPY mean RT_{NDT} value cited for the limiting Chicago Bridge and Iron case study for circumferential welds. The correction changed the 32 EFPY chemistry factor for the CB&I case study from 109.5EF to 134.9EF.

Additional Regulatory Guidance in NRC Generic Letter 98-05

On November 10, 1998, the NRC issued GL 98-05, "Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Welds," which states that BWR licensees may request permanent (i.e., for the remaining term of operation under the existing, initial license) relief from the ISI requirements of 10 CFR 50.55a(g) for the volumetric examination of circumferential reactor pressure vessel welds (ASME Code Section XI, Table IWB-2500-1, Examination Category B-A, Item No. B1.11, "Circumferential Shell Welds") by demonstrating conformance with the following safety criteria:

1) At the expiration of the operating license, the licensees will have demonstrated that limiting probability of failure for their limiting RV circumferential welds will continue to satisfy (i.e., be less than) the limiting conditional failure probability for circumferential weld assessed in the applicable BWRVIP-05 limiting case study.

2) Licensees have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the NRC staff's FSER of July 28, 1998.

In GL 98-05, the staff stated that licensees applying the BWRVIP-05 criteria would need to continue performing the volumetric inspections of all axial RV shell welds that are required by the ASME Code, Section XI, Table IWB-2500-1, Inspection Category B-A, Item B1.12 and the augmented volumetric inspections of the RV axial shell welds that are required under 10 CFR 50.55a(g)(6)(ii)(A)(2). For plants that are currently licensed to operate in accordance with their initial 40-year operating licenses, the limiting case studies are provided in Table 2.6-4 of the revised FSER on BWRVIP-05 dated March 7, 2000. For plants that have been granted operating licenses to operate for an extended period of operation, the limiting case studies are provided in Table 2.6-5 of the staff's FSER of July 28, 1998.

Additional Regulatory Guidance in the NRC SER on Topical Report BWRIP-74, as Applicable to BWR Industry Relief Requests on RV Circumferential Weld Examinations

On September 21, 1999, the BWRVIP submitted Topical Report TR-1113596, "BWRVIP-74: BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal." In Section A.4.5 of this topical report, the BWRVIP provided its assessment of what applicants for renewal would have to do in these TLAAs to support submittal of 60-year relief requests on the circumferential weld examinations after the renewed operating licenses had been issued. The staff provided its SER on BWRVIP-74 on October 18, 2001. In this FSER, the staff identified that applicants requesting renewal of BWR operating licenses would need to demonstrate that the following conditions are met for the TLAA on RV circumferential weld relief requests:

1) At the expiration of the renewed period, the mean RT_{NDT} values for their RV circumferential welds would need to satisfy the limiting conditional failure probability for circumferential welds, as stated in the staff's FSER of June 28, 1998, as amended by the staff's FSER of March 7, 2000.

2) That applicants have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER the on BWRVIP-05 Report.

The staff identified this as Renewal Applicant Action Item 11. In the NRC's FSER on the BWRVIP-74, the staff also stated that BWR applicants could propose the following alternative to meeting Renewal Applicant Action Item 11:

- Perform a plant-specific analysis to assess the probability of vessel failure at the end of the renewal period. The analysis should be consistent with the analytical approach in the NRC's FSER on BWRVIP-05, including any subsequent revisions, etc. and should be based on the chemistry of the limiting circumferential weld and predicted neutron fluence a the end of the extended period of operation. The analysis should demonstrate that the calculated probability of failure is less than or equal to that stated in Appendix E of the staff's FSER of BWRVIP-05 and should be submitted to the NRC for inspection relief.

Technical Evaluation. In RAI 4.2.5-1. dated April 8, 2005, the staff noted that on July 28, 1998, it issued an SER of BWRVIP-05. In this SER, the staff concluded that the failure frequency of RV circumferential welds in BWRs was sufficiently low to justify elimination of ISI requirements for these welds. However, the staff also indicated that examination of the RV circumferential welds would need to be performed if the corresponding volumetric examinations of the RV axial welds revealed the presence of an age-related degradation mechanism. Therefore, the staff requested confirmation from the applicant regarding whether past volumetric examinations of the BSEP RV axial welds have indicated the presence of cracking or other age-related degradation mechanisms in the welds.

The applicant provided the following response, dated May 4, 2005, to RAI 4.2.5-1:

RAI 4.2.5-1 Response

No cracking or age-related degradation mechanisms have been identified during volumetric examinations of the RV axial welds during inservice inspections to date.

The applicant's response to 4.2.5-1 confirms that the applicant's augmented and required ISI inspections of the BSEP RV axial welds have not revealed any indications of cracking in the axial welds to date. The applicant can therefore still apply its NRC-granted relief for the augmented and required ISI inspections of the BSEP RV circumferential welds for the remainder of the current operating terms, so long as any future required ISI examinations of the RV axial welds performed during the current operating terms do not indicate the presence of any age-related degradation mechanisms in the axial welds. Based on the response to RAI 4.2.5-1, it is still acceptable for the applicant to use the TLAA on RV circumferential weld relief requests as a basis for resubmitting the relief request for these welds for the period of extended operation for BSEP. Based on this assessment, the staff's concern described in RAI 4.2.5-1 is resolved.

For any given RV circumferential or axial weld material, the conditional probability of failure increases with the material's neutron fluence value and mean RT_{NDT} value, as projected to the expiration of the operating license for the facility. The neutron fluence values for the RV circumferential welds at the clad-to-base metal interface location of the RV are critical inputs to the mean RT_{NDT} estimate calculations.

As indicated in SER Section 4.2.1.2, the current 54 EFPY neutron fluence estimates for BSEP have been found to conform to the staff's recommended methodology in RG 1.190. Therefore, the neutron fluence values for this TLAA, as applicable to the clad-to-base metal interface location of the RVs at 54 EFPY, are applicable for the mean RT_{NDT} estimate calculations.

In the LRA, the applicant used the applicable 64 EFPY CB&I case study in BWRVIP-05 for circumferential welds as the case study for this TLAA. For this case study, the conditional probability of failure value for circumferential welds in CB&I RVs at 64 EFPY is 1.78×10^{-5} per reactor year. The mean RT_{NDT} value associated with this conditional probability of failure value is 70.6 EF. The applicant used this value as the acceptance criterion for this TLAA. All of this is consistent with the fabricator for the BSEP RVs and with the staff's FSER of July 28, 1998. Therefore, the CB&I case study is acceptable as the basis for evaluating this TLAA.

In RAI 4.2.5-2, dated April 8, 2005, the staff noted that in LRA Table 4.2-7, the applicant listed -50 EF as the unirradiated RT_{NDT} value for the FG circumferential welds in the RVs (i.e., the weld manufactured from Heat No. 1P4218 for Unit 1 and the weld manufactured from Heat No. 3P4000 for Unit 2) as based on the NRC approved methodology in proprietary GE topical report, NEDC-32399-P (refer to NRC SE dated December 16, 1994). However, in the applicant's response to GL 92-01, Revision 1, Supplement 1, dated August 17, 1995, CP&L stated that the 10 EF unirradiated RT_{NDT} value for the FG circumferential welds was based on application of NRC Branch Position MTEB 5-2 and informed the NRC that re-establishment of the unirradiated RT_{NDT} value for the weld would be resubmitted in accordance with the NRC's approved version of GE methdology. Therefore, the staff requested the applicant to clarify how the NRC-approved GE methodology is applicable to the RVs at BSEP and re-establishes the unirradiated RT_{NDT} value as -50 EF. The staff also requested the applicant to provide all technical data that was used to establish the unirradiated RT_{NDT} value, including any generic unirradiated Charpy-impact data used in the new determination.

The applicant provided the following response to RAI 4.2.5-2, dated May 4, 2005:

RAI 4.2.5-2 Response

A. The GE method should only be applied to interpret incomplete old test data obtained prior to the summer of 1972. The BSEP reactor vessels were ordered prior to 1972 and the issuance of Appendix G to 10 CFR 50.

The initial set of BSEP test data for the FG circumferential welds only include three Charpy V-notch tests at +10°F. No drop weight tests were performed.

This conforms to the stated criterion on use of the GE methodology.

B. The test data at +10°F for the two welds are as follows:

Heat Number 1P4218	Heat Number 3P4000
94, 91, and 90 ft-lbs	97, 95, and 88 ft-lbs

The test data are contained in Appendix C to GE Report NEDO-24161, for Unit 1, and NEDO-24157, for Unit 2. These reports were provided to the NRC as enclosures to a BSEP letter from R.P. Lopriore to the NRC, (Serial: BSEP 94-0316), "Submittal of Reactor Vessel Material Surveillance Specimen Test Results for Brunswick Unit 1," dated August 17, 1994.

10 CFR 50 Appendix G states that for vessels constructed to a version of the ASME Code prior to Summer 1972 Addendum, fracture toughness data and data analyses must be supplemented in an approved manner.

The Charpy results are used to establish the initial RT_{NDT}. First, T_{50} is established. T_{50} is the temperature at which the Charpy V-notch 50 ft-lb energy and 35 mils lateral expansion are met. Then, the initial Reference Temperature for Nil-Ductility Transition (RT_{NDT}) can be calculated from the following equation:

$$\text{Initial } RT_{NDT} = T_{50} - 60°F$$

In the absence of a Nil-Ductility Transition Temperature (NDTT) value (i.e., based upon drop weight tests), the GE Methodology requires that the value of initial RT_{NDT} be -50°F or greater.

For the two BSEP welds in question, the minimum Charpy V-notch value is greater than 50 ft-lbs, therefore, T_{50} = 10°F.

The initial RT_{NDT} is then calculated as follows:

$$\text{Initial } RT_{NDT} = T_{50} - 60°F = 10°F - 60°F = -50°F$$

Tables 4.2-5 and 4.2-6 of the BSEP LRA show the value of σ_I is set to 0°F.

The applicant's response to RAI 4.2.5-2 clearly demonstrates how the Charpy-V notch data taken at 10 EF for weld heat Nos. 1P4218 and 3P4000 conform to the staff's criteria for permitting use of the GE methodology for calculating RT_{NDT} values for welds in the absence of drop-weight test data. The applicant's response to the RAI also demonstrates how the Charpy-V notch data have been used to re-establish the unirradiated RT_{NDT} value ($RT_{NDT(U)}$) for these welds from 10 EF to -50 EF, as performed in accordance with the NRC-approved GE methodology. The RAI response also establishes the σ_I value for these welds at 0 EF consistent with the GE methodology. Since the response clarifies why it is valid to apply the GE methodology to the unirradiated $RT_{NDT(U)}$ value calculations, and how the GE methodology re-establishes the unirradiated $RT_{NDT(U)}$ value to -50 EF, and the σ_I value for these welds at 0 EF, the staff found that the applicant may use -50 EF as the $RT_{NDT(U)}$ value for weld heat Nos. 1P4218 and 3P4000. Therefore, the staff's concern described in RAI 4.2.5-2 is resolved.

The staff performed an independent calculation of the mean RT_{NDT} values for the limiting BSEP RV circumferential welds through 54 EFPY. Table 4.2.5-1 of this SE provides a summary of the mean RT_{NDT} values calculated by the staff for the BSEP RVs through 54 EFPY and a comparison of the staff's mean RT_{NDT} values to both the corresponding mean RT_{NDT} values calculated by the applicant and the mean RT_{NDT} value criterion for the limiting CB&I case study at 64 EFPY.

The results in SER Table 4.2.5-1, below, demonstrate that the mean ΔRT_{NDT} values calculated by the licensee for the BSEP RV circumferential welds are less than that for the limiting CB&I case study and are in agreement with those calculated by the staff. Based on this analysis, the staff found that the applicant has provided a valid basis for concluding that the conditional probability of failure values for the BSEP RV circumferential welds are sufficiently low to accept the TLAA and set the bases for requesting relief to eliminate the RV circumferential weld examinations for the extended period of operation once the operating licenses for BSEP have been renewed. Based on this independent assessment, the staff found that the licensee's TLAA on circumferential weld relief requests conforms to Action No. 11 on topical report BWRVIP-74-A and has been projected to 54 EFPY and is acceptable pursuant to 10 CFR 54.21(c)(1)(ii).

Table 4.2.5-1 Comparison of NRC and CP&L 54 EFPY Mean ΔRT_{NDT} Calculations to the 64 EFPY Mean ΔRT_{NDT} Calculations for the Limiting CB&I Case Study on BWRVIP-05

	Limiting 64 EFPY CB&I Case Study	NRC 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 1 (Note 1)	CP&L 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 1 (Note 1)	NRC 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 2 (Note 1)	CP&L 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 2 (Note 1)
Alloy % Cu	0.10	0.06	0.06	0.02	0.02
Alloy % Ni	0.99	0.87	0.87	0.9	0.9
$RT_{NDT(U)}$ (EF)	-65	-50	-50	-50	-50
Fluence (10^{19} n/cm^2, E > 1.0 MeV)	1.02	0.324	0.324	0.322	0.322
Chemistry Factor	134.9	82.0	82.0	27.0	27.0
ΔRT_{NDT} (EF)	135.6	56.6	56.6	18.6	18.6
Mean $_{\Delta RTNDT}$ (EF)	70.6	6.6	6.6	-31.4	-31.4
NRC Established Conditional Probability of Failure [P(F/E)] Criterion for Case / Result for Plant Specific Calculation	1.78×10^{-5} (Maximum P(F/E) value to justify relief: Refer to Note 2)	Mean ΔRT_{NDT} is Lower than Case Study Mean ΔRT_{NDT} : Criterion is met. (Note 2)	Mean ΔRT_{NDT} is Lower than Case Study Mean ΔRT_{NDT} : Criterion is met. (Note 2)	Mean ΔRT_{NDT} is Lower than Case Study Mean ΔRT_{NDT} : Criterion is met. (Note 2)	Mean ΔRT_{NDT} is Lower than Case Study Mean ΔRT_{NDT} : Criterion is met. (Note 2)

Notes: 1. For the BSEP RVs, the limiting circumferential weld materials determined by the staff were equivalent to those determined by CP&L. For Unit 1, the limiting RV circumferential weld is FG, which was fabricated from weld heat No. 1P4218. For Unit 2, the limiting RV circumferential weld is FG, which was fabricated from weld heat No. 3P4000.

2. If the plant-specific mean ΔRT_{NDT} is less than the mean ΔRT_{NDT} associated with the limiting case study, the staff concludes that probability of failure for the plant-specific circumferential weld under review will be less than the conditional probability of failure value for the limiting circumferential weld in the limiting case study. BWR plants that meet this criterion may conclude that the probability of failure for the limiting circumferential RV welds is sufficiently low enough to justify elimination of the volumetric examinations required by Section XI of the ASME Code (Examination Category B-A, Item B.1.11) and augmented volumetric examinations for the circumferential welds required by 10 CFR 50.55a(g)(6)(ii)(A)(2).

4.2.5.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the applicant's TLAA on circumferential weld relief requests:

A.1.2.1.4 RPV Circumferential Weld Examination Relief

The NRC staff issued a Safety Evaluation Report by NRC letter (G. Lainas) to the BWRVIP (c. Terry), dated July 28, 1998: "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925)." This evaluation concluded that the failure frequency of RPV circumferential welds in BWR reactors was sufficiently low to justify elimination of inservice inspection (ISI) of these welds. A supplemental Safety Evaluation Report (SER) was provided on March 7, 2000.

On November 10, 1998, the NRC issued Generic Letter (GL) 98-05, "Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on RPV Shell Welds." GL 98-05 stated that BWR licensees may request permanent relief (for the remaining term of operation under the existing license) from ISI requirements of 10 CFR 50.55a(g) for the volumetric examination of circumferential RPV welds (ASME Code Section XI, Table IWB-2500-l, Examination Category B-A, Item 1.11, "Circumferential Shell Welds"), upon demonstrating that:

1. the limiting conditional failure probability for circumferential welds satisfies the values specified in the NRC staff's July 28, 1998, SER; and

2. licensees have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the NRC staff's July 28, 1998, SER.

BSEP submitted a request for relief and has received this relief for the remaining 40- year licensed operating period.

For the period of extended operation, the 54 EFPY fluence values for BSEP are bounded by both the 32 EFPY and 64 EFPY fluence values in the NRC analysis. The BSEP Units 1 and 2 weld materials have lower copper and nickel values than those used in the NRC analysis. Hence, there is a smaller chemistry factor. As a result, the shifts in reference temperature for Units 1 and 2 are lower than both the 32 EFPY and 64 EFPY shift from the NRC SER analysis. The combination of unirradiated reference temperature ($RT_{NDT(U)}$) and shift (ΔRT_{NDT}) yields adjusted reference temperatures for Units 1 and 2 that are considerably lower than the NRC Mean analysis values. Therefore, the RPV shell weld embrittlement due to the additional fluence associated with the period of extended operation has a negligible effect on the probabilities of RPV shell weld failure. The Mean ΔRT_{NDT} values for Units 1 and 2 at 54 EFPY are bounded by the 32 EFPY and the 64 EFPY Mean ΔRT_{NDT} provided by the NRC.

Although a conditional failure probability has not been calculated, the fact that the BSEP values for Mean ΔRT_{NDT} at the end of the 60-year license are less than both the 32 EFPY and 64 EFPY values provided by the NRC leads to the conclusion that the BSEP RPV conditional failure probability is bounded by the NRC analysis. Therefore, the TLAA has been projected through the end of the period of extended operation.

The staff reviewed the applicant's UFSAR supplement summary description and found it to be adequate in addressing the applicant's response to the shift in the reference temperature and its implications on the mean ΔRT_{NDT} value calculations for the RV circumferential welds through the expiration of the period of extended operation for BSEP. Therefore, the applicant's UFSAR supplement summary description for the TLAA provides a valid description of how the TLAA was performed, as consistent with the analysis provided in Section 4.2.9 of the LRA, and a valid basis for concluding why the TLAA is acceptable when evaluated in accordance with 10 CFR 54.21(c)(1)(ii). Based on this assessment, the staff found that the UFSAR supplement summary description for this TLAA is acceptable and is in compliance with 10 CFR 54.21(d).

Section 50.55a(a)(3)(i) of 10 CFR requires that alternatives to the requirements of ASME Code, Section XI be submitted to the NRC for review and approval. Approval of the relief request on the

RV circumferential weld examinations has only been granted for the current operating terms for BSEP. Therefore, should relief be desired on the applicable RV circumferential weld examinations for the period of extended operation, the applicant must submit a relief request for the period of extended operation once the renewed operating licenses for the BSEP have been issued. However, the technical evaluation section of the relief request may be simplified by referencing the TLAA discussions/calculations in LRA Section 4.2.5 and Table 4.2-7 as the basis for requesting the relief and the staff's approval of the TLAA in SER Section 4.2.5.2. To be consistent with the criteria of GL 98-05, the technical evaluation section of the relief request will also need to address CP&L's procedures and actions for mitigating the probability of a cold, overpressurization event at the facilities.

4.2.5.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the RPV circumferential weld examination relief TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the RPV circumferential weld examination relief TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.6 RPV Axial Weld Failure Probability

In LRA Section 4.2.6, the applicant concluded that the calculation of mean ΔRT_{NDT} values for the RV beltline axial weld probability of failure analyses meets the definition of a TLAA as defined in 10 CFR 54.3. Henceforth, this TLAA will be referred to as the "TLAA on RV Axial Weld Failure Analyses."

4.2.6.1 Technical Information in the Application

The applicant provided the following assessment for the TLAA on RV axial weld failure analyses in LRA Section 4.2.6:

> **4.2.6 RPV AXIAL WELD FAILURE PROBABILITY**
>
> **Summary Description**
>
> In order to gain RPV Circumferential Weld Examination Relief as discussed in the previous subsection, it was required to demonstrate that the axial weld failure rate is no more than 5 x 10^{-6} per reactor-year. BWRVIP-05 showed that this axial weld failure rate of 5 x 10^{-6} per reactor-year is orders of magnitude greater than the 40-year end-of-life circumferential weld failure probability, and used this analysis to justify relief from inspection of the circumferential welds. As discussed in the previous Subsection, BSEP Units 1 and 2 received relief from the circumferential weld inspections for the remainder of their 40 year licensed operating period. The axial weld failure probability analysis meets the requirements of 10 CFR 54.3(a). As such, it is a TLAA.
>
> **Analysis**
>
> As stated in the previous Subsection, BSEP Units 1 and 2 received NRC approval for a technical alternative which eliminated the reactor vessel circumferential shell weld inspections for the current license term. The basis for this relief request was an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license based on BWRVIP-05 and the extent of neutron embrittlement. The NRC SER associated with BWRVIP-05 concluded that the reactor vessel failure frequency due to failure of the limiting axial welds in the BWR

fleet at the end of 40 years of operation is less than 5 x 10^{-6} per reactor-year. This failure frequency is dependent upon given assumptions of flaw density, distribution, and location. The failure frequency also assumes that "essentially 100%" of the reactor vessel axial welds will be inspected. The anticipated changes in metallurgical conditions expected over the extended licensed operating period require an additional analysis for the period of extended operation and approval by the NRC to extend the reactor vessel circumferential weld inspection relief request.

Table 4.2-8 compares the limiting axial weld 54 EFPY properties for BSEP Units 1 and 2 against the values taken from Table 3 found in the supplement to the NRC SER for BWRVIP-05. The SER supplement required the limiting axial weld to be compared with data found in Table 3. The supplemental SER states:

> *A third calculation, with an initial ΔRTNDT of -2 °F and a mean ΔRT_{NDT} of 114°F, was chosen to identify the mean value of ΔRT_{NDT} required to provide a result which closely matches the RPV failure frequency of 5 x 10^{-6} per reactor-year.*

The BSEP evaluation is therefore performed using data from "Mod 2" of Table 3 of the supplement. The limiting axial welds at BSEP Units 1 and 2 are all welds with similar chemistry. As shown in Table 4.2-8, the limiting weld chemistry, chemistry factor, and 54 EFPY mean ΔRT_{NDT} values are within the limits of the values assumed in the analysis performed by the NRC staff in the BWRVIP-05 SER supplement. Thus, the probability of failure for the axial welds is bounded by the NRC evaluation.

Therefore, this TLAA has been demonstrated to remain valid for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(ii) – The RPV axial weld analyses have been projected to the end of the period of extended operation.

4.2.6.2 Staff Evaluation

Regulatory Evaluation.

Inservice Inspection Requirements, NRC Criteria on the BWRVIP-05 Report, and Generic Letter 98-05 Criteria

The regulatory bases for the TLAA on RV axial weld failure analyses are given in the following subsections under "Regulatory Evaluation" in Section 4.2.5.2:

- Inservice Inspection Requirements
- Augmented Inservice Inspection Requirements for RV Shell Welds
- Additional Regulatory Guidance on the NRC's Safety Evaluation (SE) of the BWRVIP-05 Report
- Additional Regulatory Guidance in NRC Generic Letter 98-05

Additional Regulatory Guidance in the NRC SER on Topcial Report BWRIP-74, as Applicable to BWR Industry RV Axial Weld Probability fo Failure Analyses

In Section A.4.5 of BWRVIP-74, the BWRVIP provided an assessment of what applicants for renewal would have to do in these TLAAs to support submittal of 60-year relief requests regarding the circumferential weld examinations after the renewed operating licenses had been issued. The staff provided its FSER on BWRVIP-74 on October 18, 2001. In this FSER, the staff made the following assessment of the impact of LRAs on RV axial weld probability of failure analyses:

> The BWRVIP-74 report does not indicate the impact of neutron embrittlement on BWR axially oriented RPV welds. However, in its July 28, 1998, letter to Carl Terry,

the staff identified a concern about the failure frequency of axially oriented welds in BWR RPVs. In a response to this concern, the BWRVIP provided evaluations of axial weld failure frequency in letters dated December 15, 1998 and November 12, 1999. The staff's evaluation of these analyses is contained in a March 7, 2000, letter to Carl Terry. The FSER enclosed in that letter states that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5×10^{-6} per reactor year, given the assumptions on flaw density, distribution and location, as described in the FSER. Since the results apply only for the initial 40-year license period of BWR plants, LR applicants shall provide plant-specific information applicable to 60 years of operation.

The BWRVIP identified Clinton and Pilgrim as the reactor vessels with the highest mean ΔRT_{NDT} in the BWR fleet. The staff confirmed this conclusion by comparing the information contained in the BWRVIP analysis and the information contained in the reactor vessel integrity database (RVID) for all BWR RPV axial welds. The staff performed analyses of the Clinton and Pilgrim plants. The results from the staff calculations are provided in Table 1. The staff calculations used the basic input information for Pilgrim, with three different assumptions for the initial ΔRT_{NDT}. The calculations of the actual Pilgrim condition used the docketed initial ΔRT_{NDT} of -48 EF and a mean ΔRT_{NDT} of 68 EF. A second calculation, listed as "Mod 1" in Table 1, is consistent with the BWRVIP calculations, with an initial ΔRT_{NDT} of 0 EF and a mean ΔRT_{NDT} of 116 EF. A third calculation, with an initial ΔRT_{NDT} of -2 EF and a mean ΔRT_{NDT} of 114 EF, was performed to identify the mean ΔRT_{NDT} value required to provide a result which closely matches the RPV failure frequency of 5×10^{-6} per reactor-year.

Table 1: Comparison of Results from Staff and BWRVIP

Plant	Initial ΔRT_{NDT} (EF)	Mean ΔRT_{NDT} (EF)	RV Probability of Failure Values (Vessel Failure Freq.)	
			Staff	BWRVIP
Clinton	-30	91	2.73 E -6	1.52 E -6
Pilgrim	-48	68	2.24 E -7	-------
Mod 1 *	0	116	5.51 E -6	1.55 E -6
Mod 2 **	-2	114	5.02 E -6	-------

* A variant of Pilgrim input data, with initial ΔRT_{NDT} = 0 EF.

** A variant of Pilgrim input data, with initial ΔRT_{NDT} = -2 EF

As indicated in the March 7, 2000, letter, an applicant shall monitor the axial beltline weld embrittlement. One acceptable method is to determine the mean ΔRT_{NDT} of the limiting axial beltline weld at the end of the extended period of operation is less than the values specified in Table 1. This is Renewal Applicant Action Item 12.

In the staff’s FSER on BWRVIP-74, the staff stated that applicants applying for license renewal of BWR facilities should demonstrate how they satisfy Renewal Applicant Action Item 12. As stated in the quoted NRC position, one acceptable method would be to demonstrate that the mean ΔRT_{NDT} value for the limiting RV axial beltline weld at the end of the extended period of operation is less than one of the corresponding values specified in Table 1 on the previous page.

Technical Evaluation. In the staff’s FSER on BWRVIP-74 dated October 18, 2001, it was noted that the staff’s conclusions in the supplemental FSER on BWRVIP-05, as issued on March 7, 2000, provide the bases for reviewing TLAAs on RV axial weld failure analyses. In the supplemental FSER on BWRVIP-05, the staff established that the vessel failure frequencies associated with the Clinton and Pilgrim RV axial welds were the limiting vessel failure frequencies for RV axial welds among U.S. BWRs. In these calculations, the vessel failure frequency for the RV axial welds is calculated from the conditional probability of failure frequency for the axial welds multiplied by a 1×10^{-3} probability of initiating a cold, overpressurization event at the facilities.

Table 1 provides the vessel failure frequency criteria for the Clinton case study and three variations of the Pilgrim case study (including “Mod-1" and “Mod-2" variants). Table 1 also includes the maximum mean ΔRT_{NDT} values that correspond to the vessel failure frequency values for these case studies. With respect to these case studies, Clinton represents the case study for RV axial welds in CB&I fabricated RVs and the three variants of Pilgrim case study represent the case studies for Combustion Engineering fabricated RVs. There are no associated axial weld case studies for Rotterdam fabricated RVs because the beltline regions in Rotterdam fabricated RVs are fabricated from RV shell ring forgings and therefore do not include RV axial beltline welds.

In RAI 4.2.6-1, dated April 8, 2005, the staff noted that in LRA Table 4.2-8, the applicant indicated that it had opted to use the Pilgrim “Mod 2" case study as the limiting case study for assessing the vessel failure frequency value for the BSEP RV axial welds at 54 EFPY. The applicant indicated that the vessel failure frequency value for this case study is 5.02×10^{-6} and that associated mean ΔRT_{NDT} value for the vessel failure frequency value criterion is 114 EF. The staff reviewed the data for the BSEP RVs in the NRC’s RVID. The BSEP units are fabricated with CB&I RVs. Therefore, the staff inquired why the applicant had opted to use the “Mod 2" variant of the Pilgrim case study as the basis for this TLAA in lieu of the Clinton case study, which is the case study for beltline axial welds in CB&I RVs.

The applicant provided the following response, dated May 4, 2005, to RAI 4.2.6-1:

RAI 4.2.6-1 Response

The NRC Supplemental SER on Topical Report BWRVIP-05, dated March 7, 2000, concluded:

> The results of these calculations indicate that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet are below 5×10^{-6} per reactor-year, given the assumptions on flaw density, distribution and location described previously.

The "Mod 2" variant of the Pilgrim Case Study, with a failure frequency of 5.02×10^{-6} per reactor-year, was chosen because it most closely aligns with the conclusion of the safety evaluation report.

The applicant’s response to the RAI indicated that the applicant applied the “Mod 2" variant of the Pilgrim case study because the vessel failure frequency for the case study conforms most closely with that applied by the staff in its FSER on BWRVIP-74, dated October 18, 2001. Since the applicant applied the case study that most closely matches the vessel failure frequency applied by the staff, the staff found that the applicant may use the “Mod 2" variant of the Pilgrim case study as the basis for assessing the TLAA on RV Axial Weld Failure Analyses. Therefore, the staff’s concern described in RAI 4.2.6-1 is resolved.

In the staff’s supplemental SER on BWRVIP-05, the staff established that the mean ΔRT_{NDT} values for a given probability of failure analysis are calculated as the sum of the unirradiated adjusted reference temperature for the RV beltline material and the shift in adjusted reference temperature value induced by neutron irradiation (i.e., mean $\Delta RT_{NDT} = RT_{NDT(U)} + \Delta RT_{NDT}$) and that a margin term uncertainty allowance is not included as part of the calculations. The staff performed independent calculations of the mean ΔRT_{NDT} values for the BSEP RV beltline axial welds in accordance with this position.

SER Table 4.2.6-1 provides the results of the staff’s independent calculations and a comparison with the mean ΔRT_{NDT} values calculated by the applicant and both the “Mod 2" and Clinton case studies for BWR RV axial welds. The table also provides the staff’s conclusions on whether the vessel failure frequency analysis results for the BSEP RV axial welds are acceptable and the staff’s basis for making these conclusions.

The staff’s independent mean ΔRT_{NDT} value calculations for the BSEP RV beltline axial welds, as summarized, below, in Table 4.2.6-1, are lower than the limiting mean ΔRT_{NDT} values for both the Clinton and Pilgrim “Mod 2" case studies and therefore demonstrate that the vessel failure frequencies for the BSEP RV beltline axial welds are lower than those for either case study. Based on this assessment, the staff found that the applicant’s TLAA on RV axial weld failure analyses satisfies Renewal Application Action Item 12 of the staff’s SER on BWRVIP-74, dated October 18, 2001. The staff further found that the TLAA on RV axial weld failure analyses has been projected to the end of the period of extended operation for BSEP and is acceptable, as evaluated in accordance with the criterion of 10 CFR 54.21(c)(1)(ii).

Table 4.2.6-1 Comparison of NRC and CP&L 54 EFPY Mean ΔRT_{NDT} Calculations for BSEP Reactor Vessel Beltline Axial Weld Probability of Failure Analyses

	Limiting Clinton Case Study	Limiting Pilgrim “Mod 2" Case Study	NRC 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 1 (Note 1)	SNC 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 1 (Note 1)	NRC 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 2 (Note 1)	SNC 54 EFPY Mean ΔRT_{NDT} Calculations for Unit 2 (Note 1)
Alloy % Cu	0.100	0.219	0.05	0.05	0.05	0.05
Alloy % Ni	1.08	0.996	0.96	0.96	0.049	0.96
$RT_{NDT(U)}$ (EF)	-30.0	-2.0	10.0	10.0	10.0	10.0
Fluence (10^{19} n/cm^2)	0.690	0.149	0.256	0.256	0.252	0.252

Chemistry Factor	135.0	232.0	68.0	68.0	68.0	68.0
ΔRT_{NDT} (EF)	121.0	116.0	42.8	43.0	42.5	43.0
Mean $_{\Delta RTNDT}$ (EF)	91.0	114.0	52.8	53.0	52.5	53.0
NRC Vessel Failure Frequency (VFF) Criterion / Conclusion Against the Criterion (Note 3)	2.73×10^{-6} (Maximum VFF Value Refer to: Note 2)	5.02×10^{-6} (Maximum VFF Value Refer to: Note 2)	The Mean ΔRT_{NDT} is Lower than the Mean ΔRT_{NDT} in either Case Study: Acceptance criterion is met. (Note 2)	The Mean ΔRT_{NDT} is Lower than the Mean ΔRT_{NDT} in either Case Study: Acceptance criterion is met. (Note 2)	The Mean ΔRT_{NDT} is Lower than the Mean ΔRT_{NDT} in either Case Study: Acceptance criterion is met. (Note 2)	The Mean ΔRT_{NDT} is Lower than the Mean ΔRT_{NDT} in either Case Study: Acceptance criterion is met. (Note 2)

Notes: 1. For the BSEP RVs, the limiting axial weld materials determined by the staff were equivalent to those determined by CP&L. For both Unit 1 and Unit 2, the limiting RV axial welds are the F1 and F2 axial welds. All of these welds are fabricated from Weld Heat No. S3986. The NRC and CP&L independently identified a $RT_{NDT(U)}$ value of 10 EF, a Copper content of 0.05 wt.-%, and a Nickel content of 0.96 wt.-% for these weld materials.

2. If the plant-specific mean ΔRT_{NDT} is less than the mean ΔRT_{NDT} associated with the limiting case study, the staff concludes that probability of failure for the plant-specific axial weld under review will be less than the NRC's maximum acceptable vessel failure frequency for the axial weld assessed in the limiting RV axial weld case study. BWR plants that meet this criterion may conclude that the probability of failure for their RV beltline axial welds is acceptable and that the TLAA has been sufficiently projected through the expiration of the extended period and is acceptable when evaluated against the TLAA acceptance criterion of 10 CFR 54.21(c)(1)(ii)/2.

3. In these calculations, the vessel failure frequency for the axial weld in the case study analyses is calculated using the case study's conditional probability of failure value multiplied by a 1×10^{-3} frequency for initiation of a cold, overpressurization event. Thus, for the staff's calculation of the vessel failure frequencies for the Clinton and Pilgrim "Mod 2" case studies, the staff determined that the conditional probability for the axial welds was 2.73×10^{-3} for the Clinton case study and 5.02×10^{-3} for the Pilgrim "Mod 2" case study.

4.2.6.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the applicant's TLAA on RV Axial Weld Failure Analyses:

A.1.2.1.5 RPV Axial Weld Failure Probability

In order to gain RPV circumferential weld examination relief, it was required to demonstrate that the axial weld failure rate is no more than 5×10^{-6} per reactor-year. The basis for this relief request was an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license based on BWRVIP-05 and the extent of neutron embrittlement. The NRC SER associated with BWRVIP-05 concluded that the reactor vessel failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is less than 5×10^{-6} per reactor-year.

> A comparison has been made between the limiting axial weld properties at 54 EFPY for BSEP Units 1 and 2 against the values taken from Table 3 found in the supplement to the NRC SER for BWRVIP-05. The limiting axial welds at BSEP Units 1 and 2 are all welds with similar chemistry. Based on the comparison, the limiting weld chemistry, chemistry factor, and 54 EFPY mean ΔRT_{NDT} values are within the limits of the values assumed in the analysis performed by the NRC staff. Thus, the probability of failure for the axial welds is bounded by the NRC evaluation. Therefore, the axial weld failure analysis has been demonstrated to remain valid for the period of extended operation.

In the LRA Table 4.2-8, the applicant indicated that it had opted to use the Pilgrim "Mod 2" case study as the limiting case study for assessing the probability of failure values for the BSEP RV axial welds at 54 EFPY. The 5 x 10^{-6} probability of failure value cited in the applicant's UFSAR supplement summary description corresponds to maximum probability of failure criterion approved by the staff in its amended SER on BWRVIP-05, dated March 7, 2000. In its response to RAI 4.2.6-1, the applicant indicated that it had selected the Pilgrim "Mod 2" limiting case study as the case study for the vessel failure frequency analyses because the NRC-calculated vessel failure frequency value for the case study most closely matched up with the NRC's vessel failure frequency criterion of 5 x 10^{-6}, as stated in the staff's supplement FSER on BWRVIP-05, dated March 7, 2000.

In SER Section 4.2.6.2, the staff concluded that the applicant's answer to RAI 4.2.6-1 provided an acceptable basis for using the Pilgrim "Mod 2" limiting case study as the case study for this TLAA and that the mean ΔRT_{NDT} values for the RV axial welds were sufficiently bounded by the associated mean ΔRT_{NDT} value for the Pilgrim "Mod 2" limiting case study. In SER Section 4.2.6.2, the staff further concluded that the applicant had provided an acceptable basis for concluding that vessel frequency values for the BSEP RV axial welds had been acceptably projected through the period of extended operation for BSEP, as evaluated in accordance with the criterion in 10 CFR 54.21(c)(1)(ii). The applicant's UFSAR supplement summary description provides sufficient technical information for making this conclusion and is consistent with the analysis in SER Section 4.2.6.2. The staff, therefore, found that the UFSAR supplement summary description provides an acceptable summary of the TLAA on RV axial weld failure analyses, is acceptable, and is in compliance with 10 CFR 54.21(d).

4.2.6.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the RPV axial weld failure probability TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the RPV axial weld failure probability TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.7 Core Shroud Reflood Thermal Shock Analysis

In LRA Section 4.2.7, the applicant concluded that the core shroud thermal shock reflood analysis is a TLAA as defined in 10 CFR 54.3. Henceforth, this TLAA will be referred to as the "TLAA on Core Shroud Thermal Shock."

4.2.7.1 Technical Information in the Application

The applicant provided the following assessment for the TLAA on core shroud thermal shock in LRA Section 4.2.7:

4.2.7 CORE SHROUD REFLOOD THERMAL SHOCK ANALYSIS

Summary Description

Section 3.9.2.5 of the BSEP USFAR includes an end-of-life (40-year) thermal shock analysis performed for the core shroud for a design basis loss-of-coolant accident (LOCA) followed by a low-pressure coolant injection. The reflood shock refers to the stress imposed upon the shroud due to contact between the hot shroud and the cold water injected to reflood the vessel. The ability of the shroud to withstand this shock was determined by comparing the amount of strain that would be imposed by the shock loading to the amount of strain the material could withstand, using material property values that would be expected after 40 years of radiation exposure. Since the material properties were based upon 40-year fluence values, they meet the requirements of 10 CFR 54.3(a). As such, the analysis based upon these properties is a TLAA.

The current analysis states:

> *The most irradiated point on the inner surface of the shroud is subjected to a total integrated neutron flux of 6.2 x 10^{20} nvt (>1.0 MeV) by the end of plant life. The peak thermal shock stress is 155,700 psi, corresponding to a peak strain of 0.57 percent. The shroud material is Type 304 stainless steel. Data for irradiated stainless steel at higher flux levels show the material will strain to 50 percent before failure. Therefore, the peak strain resulting from thermal shock at the inside of the shroud represents no loss of integrity of the reactor vessel inner volume.*

Analysis

As discussed above, core shroud components were evaluated for a reflood thermal shock event, considering the embrittlement effects of lifetime radiation exposure. The analysis includes the most irradiated point on the inner surface of the shroud where the calculated value of fluence for 40-year operating period is below the threshold (6.2E+20 n/cm^2) for material property changes due to irradiation. However, using the approved fluence methodology discussed in Subsection 4.2.1, the 54 EFPY fluence at the most irradiated point on the core shroud was calculated to be 4.17E+21 n/cm^2. The peak strain of 0.57% represents a considerable margin of safety below measured values of percent elongation for annealed Type 304 stainless steel irradiated to 8.0E+21 n/cm^2 (neutrons with energy level E >1.0 Million electron Volts). The measured value of percent elongation for stainless steel weld metal is 4% for a temperature of 297°C (567°F) with a neutron flux of 8.0E+21 n/cm^2 (E >1.0 MeV), while the average value for base metal at 290°C (554°F) is 20% based on values provided in BWRVIP-35. Since the 54 EFPY fluence at the most irradiated point on the core shroud was calculated to be less than 8.0E+21n/cm^2 (E >1.0 MeV), the thermal shock effects on the shroud at the point of highest irradiation level will not jeopardize the proper functioning of the shroud following the design basis accident during the period of extended operation. Therefore, this TLAA has been demonstrated to remain valid for the period of extended operation.

Disposition: 10 CFR 54.21(c)(1)(ii) – The core shroud reflood thermal shock analyses have been projected to the end of the period of extended operation.

4.2.7.2 Staff Evaluation

Regulatory Evaluation. UFSAR Section 3.9.2.5 provides the regulatory basis for the BSEP core shroud reflood thermal shock analysis. In this section of the UFSAR, the applicant provided its dynamic system analysis of the BSEP RV internals under faulted conditions. In the UFSAR section, the applicant identified that the most severe thermal shock event for the RV internals results from the post-design-basis accident core flooding and discussed how the peak strains in the RV internals are acceptable for the 40-year design-basis ASME Code Section III fatigue cycles and the limiting 40-year neutron fluence value for the core shroud structures.

Technical Evaluation. In UFSAR Section 3.9.2.5, the applicant identified that the limiting reflood event for the RV internals is a post-LOCA, low pressure coolant injection (LPCI) reflood of the core shroud region. The UFSAR section provides a 40-year analysis to demonstrate the BSEP RV core shrouds would be capable of maintaining their geometry during a postulated LOCA, even if LPCI flooding of the core shroud were to occur as an automatic ECCS or operator-initiated response to the event. The NRC does not require this analysis to be performed as part of the CLB for the facility; however, this analysis is required to be evaluated under the criteria of 10 CFR 54.21(c)(1) because the applicant identified the analysis as a TLAA as defined in 10 CFR 54.3.

The analysis in UFSAR Section 3.9.2.5 indicates that the following core shroud locations are the most limiting locations for the RV core shroud reflood thermal shock analysis:

- shroud support plate
- shroud-to-shroud support plate discontinuity
- shroud inner surface at the highest irradiation zone (beltline region)

The BSEP core shrouds are fabricated from Type 304 austenitic stainless steel plate materials and equivalent Type 304 weld materials. Of these core shroud locations, the inside surface of the shroud in the beltline region of the RV is the location that relates to the TLAA because the increase in neutron fluence during the extended period of operation could decrease the allowable strain at failure for this region of the core shroud. The strain value in the original 40-year analysis is based on the loads associated with the post-LOCA LPCI reflooding and a conservative assumption that the core shroud would be subject to the limiting neutron fluence of 6.2×10^{20} n/cm^2 (E > 1.0 MeV) at the expiration of the current operating term. In LRA Section 4.2.7, the applicant indicated that the limiting neutron fluence for the BSEP core shrouds is projected to be 4.17×10^{21} n/cm^2 (E > 1.0 MeV) at 54 EFPY. The applicant's design basis establishes that the applicant is using a percent-elongation parameter as the parameter for measuring the amount of strain in the BSEP core shrouds.

RAI 4.2.7-1, Parts A and B, dated April 8, 2005, states that in reviewing this TLAA, the staff could not determine what acceptance criterion was being used for the maximum amount of allowable strain that could be tolerated in the core shrouds during a reflooding event or what limit was being established on integrated neutron flux to be consistent with the maximum allowable strain criterion. Therefore, the staff requested the applicant to clarify what percent-elongation acceptance criterion was being used for the TLAA assessment and what bounds were being established on maximum neutron fluence level (i.e., in n/cm^2, E > 1.0 MeV) to be consistent with the applicant's percent-elongation strain acceptance criterion for the TLAA assessment.

The applicant provided the following response to RAI 4.2.7-1, dated May 4, 2005:

RAI 4.2.7-1 Response

A. BWRVIP-35, "Fracture Toughness and Tensile Properties of Irradiated Austenitic Stainless Steel Components Removed from Service," EPRI TR-108279, dated June 1997, provides data on fracture toughness and tensile properties of austenitic stainless steel in-core components removed from service in an operating nuclear power plant. These samples include weld materials and plate materials. Both the plate and weld materials were exposed to neutron fluence of 8.0E+21 n/cm^2 (E>1.0 MeV). Tensile tests were performed for each group of the samples with the following results.

- The average percent elongation for weld materials tested at 290°C (i.e., 554°F) was 4 percent. This 4 percent elongation value was used as the acceptance criterion for evaluating core shroud welds in the TLAA assessment.

- The average percent elongation for plate materials tested at 297°C (i.e., 567°F) was 20 percent. This 20 percent elongation value was used as the acceptance criterion for evaluating core shroud plate materials in the TLAA assessment.

- The 8.0E+21 n/cm^2 (E>1.0MeV) neutron fluence value is considered to be the limit for applying these test results. However, this value is not expected to be exceeded within 60 years. The 54 EFPY fluence value at the most irradiated point on the shroud was calculated to be 4.17E+21 n/cm^2 (E>1.0MeV), using approved fluence methodology. If it is determined that this fluence value will be exceeded, the core shroud reflood thermal shock analysis will be refined or another suitable evaluation will be developed as necessary.

B. BWRVIP-35 provides actual results from tensile tests performed on samples taken from in-core components removed from an operating nuclear power plant after long periods of service. The technical basis for using these results is that they are representative of the material properties expected for similar materials under similar operating conditions, including neutron fluence and temperature. BWRVIP-35 has not been reviewed and approved by the NRC.

In its response to RAI 4.2-7-1, Part A, the applicant clarified that core shroud reflood thermal shock analysis sets a maximum amount of allowable strain of 4.0 percent-elongation for the core shroud plates and 20.0 percent-elongation for the core shroud welds. The applicant also clarified that the analysis established a 8.0 x 10^{21} n/cm^2 (E > 1.0 MeV) limit on the neutron fluence levels, which, if exceeded, would require the applicant to either refine the core shroud thermal shock analysis or to develop another suitable evaluation if the limit on the neutron fluence is exceeded. The applicant's response to RAI 4.2.7-1, Part A, also clarified that the limiting neutron fluence for the BSEP core shrouds is projected to be 4.17 x 10^{21} n/cm^2 (E > 1.0 MeV) at 54 EFPY and that this is below the acceptable limit established on neutron fluence for GE's core shroud thermal shock analysis (i.e., the core shroud strain analysis). Therefore, the staff's concern described in RAI 4.2.7-1, Part A, is resolved.

In its response to RAI 4.2.7-1, Part B, the applicant clarified that the BWRVIP-35 provides the actual tensile test results performed on samples taken from in-core components removed from an operating nuclear power plant after a long period of service and that the results are considered to be representative of the material properties (stress/strain properties) for core shrouds at BSEP because they are made from materials and are exposed to operating conditions similar to those for BSEP. The staff found that this is a valid basis for applying the BWRVIP-35 tensile test results to the TLAA on core shroud thermal shock. Therefore, the staff's concern described in RAI 4.2.7-1, Part B, is resolved.

The applicant's TLAA description provides a sufficient summary to demonstrate that the neutron fluence values for the core shrouds have been projected out to 54 EFPY and that the analysis remains acceptable because the limiting 54 EFPY core shroud neutron fluence values for the core shroud will be less than the acceptable limit established on neutron fluence for GE's core shroud thermal shock analysis. Based on this analysis, the staff found that the applicant's TLAA on core shroud thermal shock has been projected to the expiration of the period of extended operation for BSEP and is acceptable pursuant to 10 CFR 54.21(c)(1)(ii).

4.2.7.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the TLAA on core shroud thermal shock:

> A.1.2.1.6 Core Shroud Reflood Thermal Shock Analysis
>
> BSEP has been analyzed for an end-of-life (40-year) thermal shock analysis performed for the core shroud for a design basis loss-of-coolant accident (LOCA) followed by a low-pressure coolant injection. The reflood shock refers to the stress imposed upon the shroud due to contact between the hot shroud and the cold water injected to reflood the vessel. The ability of the shroud to withstand this shock was determined by comparing the amount of strain that would be imposed by the shock loading to the amount of strain the material could withstand, using material property values that would be expected after 40 years of radiation exposure. The original analysis compared the calculated thermal shock material strain (0.57%) to the strain required to fail the material (50%) and concluded that the peak strain resulting from thermal shock at the inside of the shroud represents no loss of integrity of the reactor vessel inner volume.
>
> For License Renewal, the predicted neutron fluence exceeds the value assumed in the original analysis. The 54 EFPY fluence at the most irradiated point on the core shroud was calculated to be less than 8.0E+21 n/cm^2 (E >1.0 MeV). However, the measured value of percent elongation for stainless steel weld metal is 4% for a temperature of 297°C (567°F) with a neutron flux of 8.0E+21 n/cm^2 (E >1.0 MeV), while the average value for base metal at 290°C (554°F) is 20% based on values provided in BWRVIP-35. Thus, the thermal shock effects on the shroud at the point of highest irradiation level will not jeopardize the proper functioning of the shroud following the design basis accident during the period of extended operation. Therefore, the core shroud reflood thermal shock analysis has been demonstrated to remain valid for the period of extended operation.

The applicant's UFSAR supplement summary description provides the same technical information and bases for the TLAA as is described in LRA Section 4.2.7. The UFSAR supplement summary description also indicates that the neutron fluence used in the core shroud reflood thermal shock analysis is bounding for the neutron fluences that are projected to occur at the inside surfaces of the BSEP core shrouds at 54 EFPY. Based on this summary description, the staff found that the UFSAR supplement summary description has sufficient information to indicate why the previous analysis has been projected through the expiration of the period of extended operation for BSEP, as consistent with the criterion of 10 CFR 54.21(c)(1)(ii), and that the UFSAR supplement summary description is acceptable and in compliance with 10 CFR 54.21(d).

4.2.7.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the core shroud reflood thermal shock analysis TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the core shroud reflood thermal shock analysis TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.8 Core Plate Plug Spring Stress Relaxation

In LRA Section 4.2.7, the applicant concluded that the core plate plug spring stress relaxation analysis is a TLAA as defined in 10 CFR 54.3. Henceforth, this TLAA will be referred as the “TLAA for the Core Plate Plugs.”

4.2.8.1 Technical Information in the Application

The applicant provided the following assessment of the TLAA for the core plate plugs in LRA Section 4.2.8:

> **4.2.8 CORE PLATE PLUG SPRING STRESS RELAXATION**
>
> **Summary Description**
>
> In the mid-1970s, mechanical-type core plate plugs were installed in the bypass flow holes of the core support plates of various BWR/4s. The plugs were intended to limit flow through bypass flow holes and reduce flow-induced vibration of in-core neutron monitors and start-up sources against the corners of the fuel assemblies. The spring loaded plugs were designed to withstand typical and worst-case transient differential pressures. Brunswick Unit 2 has installed these mechanical plugs. The Alloy X-750 spring that provides preload to the core plate plug will relax as a function of thermal and neutron exposure. The loss of preload may cause the plug to leak at a higher rate than the design value, producing possible flow induced vibration effects that can influence other components in the core. It should be noted that Brunswick Unit 1 does not have the mechanical plugs, but has welded plugs which do not have the springs subject to this aging effect.
>
> The projected relaxation is based upon 40-year fluence values, although it was only shown to be valid for up to 24 EFPY. It has been conservatively determined to be a TLAA, and will be evaluated as such in accordance with 10 CFR 54.3(a).
>
> **Analysis**
>
> Since the spring relaxation would exceed acceptable limits if exposed to a 54 EFPY fluence value, projecting the analysis for 60 years is not feasible. Therefore, loss of preload due to stress relaxation of the core plate plug spring will be managed by the Reactor Vessel and Internals Structural Integrity Program.
>
> **Disposition 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) of the core plate plug springs will be adequately managed for the period of extended operation.**

4.2.8.2 Staff Evaluation

Regulatory Evaluation. In RAI 4.2.8-1, Part A, dated April 8, 2005, stated that in LRA Section 4.2.8, the applicant indicated that the analysis for installing the spring-loaded Unit 2 core plate plugs is a TLAA for the LRA because the amount of stress relaxation in the plugs is, in part, dependent on the accumulated neutron fluence in the plugs. However, the applicant did not reference the specific title and date of the analysis that meets the criteria for this TLAA. Therefore, the staff requested that the applicant reference by title and date which design-basis or CLB document establishes the stress relaxation analysis for spring loaded core plate plugs as a TLAA for the application. The staff also requested that the applicant clarify whether the analysis is a generic or plant-specific analysis and whether the analysis has been approved by the staff. If the analysis had been approved, the staff requested that the applicant reference the date of the staff’s safety evaluation on the stress-relaxation analysis.

In its response, by letter dated May 4, 2005, tthe applicant stated:

> **RAI 4.2.8-1 Response**
>
> **Part A.** A plant-specific analysis was performed for the purpose of extending the life of the core plate plugs beyond GE's revised service life. This analysis has not been approved by the NRC staff. This plant-specific analysis was conservatively considered to be a TLAA. As stated on page 4.2-13 of the LRA:
>
> > The projected relaxation is based upon 40-year fluence values, although it was only shown to be valid for up to 24 EFPY.
>
> Since the 24 EFPY is less than the currently projected 32 EFPY at 40 years, BSEP chose to manage these components by replacing them at the end of their qualified life by using AMP B.2.28, Reactor Vessel and Internals Structural Integrity Program, described on page B-74 of the LRA.

The applicant's response to RAI 4.2.8-1, Part A, indicated that GE had placed a qualified limit on the service life for the Unit 2 spring-loaded core plate plugs on their installation at Unit 2 and that the applicant had performed a plant-specific engineering analysis to evaluate whether the service life of the Unit 2 spring-loaded core plate plugs could be extended beyond that qualified by GE. The applicant stated that it had conservatively identified this plant-specific evaluation as a TLAA for the LRA, as consistent with the definition for TLAAs in 10 CFR 54.3. This is an acceptable and conservative practice and is acceptable. Therefore, the staff's concern described in RAI 4.2.8-1, Part A, is resolved

Technical Evaluation. In LRA Section 4.2.8, the applicant concluded that previous structural analysis for the spring-loaded Unit 2 core plate plugs could not provide assurance the degree of stress relaxation in the plugs would remain at acceptable levels during the extended period of operation for Unit 2. In its response to RAI 4.2.8-1, Part B, below, the applicant clarified that the projected amount of relaxation in the plugs is based on 40-year values but has only been shown to be qualified to 24 EFPY. The applicant stated that, consistent with TLAA 4.2.8, the applicant would credit the RV&ISIP to manage stress relaxation in the Unit 2 spring-loaded core plate plugs. This is in compliance with the TLAA criterion in 10 CFR 54.21(c)(1)(iii) in that the applicant is crediting an AMP for aging management because the plant-specific evaluation cannot be relied upon to assure adequate aging management of stress relaxation in the core plate plugs.

The applicant's RV&ISIP is discussed in LRA Section B.2.28. In this section, the applicant identified the RV&ISP as an existing plant-specific AMP for managing age-related degradation in the BSEP RV internal components. Therefore, the RV&ISIP is an appropriate AMP to credit for aging management of stress relaxation in the Unit 2 spring-loaded core plate plugs. The staff evaluates the RV&ISIP in SER Section 3.0.3.3.1. The scope of the staff's evaluation of this AMP includes resolution of RAI B.2.28-6 on the ability of the AMP to manage loss of preload/stress relaxation in the Unit 2 spring-loaded core plate plugs. Based on this analysis, the staff found that the applicant's TLAA on stress relaxation of the Unit 2 core plate plugs complies with 10 CFR 54.21(c)(1)(iii), in that the applicant is using an appropriate AMP to manage stress relaxation in the spring-loaded Unit 2 core plug plugs.

In RAI 4.2.8-1, Part B, the staff requested the following information:

> In BWRVIP-25, the BWRVIP established that core plate designs with rim hold down bolts would need to treat stress relaxation of the bolts as a potential TLAA. This was identified as Applicant Action Item No. 3 on BWRVIP-25. To respond to this Action Item (i.e. in Table 3 of AMP No. B.2.28 of the BSEP-1/2 LRA), CP&L stated that “the potential susceptibility of the rim hold down bolts to stress relaxation was evaluated as a potential TLAA, but no TLAA was identified.” This is consistent with page 3.1-51 of LRA Table 3.1-1, in which CP&L does not identify stress relaxation as an applicable aging effect requiring management for the core plate bolts. The following clarification was necessary for completion of the staff’s review:
>
> (1) Clarify whether the core plate rim hold down bolts are within the scope of license renewal and require an aging management review (AMR). Confirm whether or not the core plate bolts referred to on page 3.1-51 of LRA Table 3.1-1 are the same components as the core plate rim hold down bolts that are referred to on page B-82 of the application.
>
> (2) If the core plate rim hold down bolts do require an AMR, justify your basis for concluding that stress relaxation does not require aging management and for concluding that a TLAA is not appropriate for the core plate rim hold down bolts, as is otherwise recommended in BWRVIP-25. If CP&L determines that loss of preload/stress relaxation of the core plate rim hold down bolts is an aging effect requiring management, amend LRA Table 3.1-1 to include an AMR entry on how loss of preload/stress relaxation will be managed in the components during the periods of extended operation for BSEP-1/2. If CP&L determines that a TLAA is necessary to manage loss of preload/stress relaxation in the core plate rim hold down bolts, amend Chapter 4.0 of the BSEP-1/2 LRA to include a TLAA on loss of preload/stress relaxation of the core plate rim hold down bolts.

In its response, by letter dated May 4, 2005, the applicant stated:

> **RAI 4.2.8-1 Response**
>
> **Part B.**
>
> 1. The core plate rim hold down bolts are within the scope of License Renewal and require an AMR. However, the AMR for core plate bolts appears on page 3.1-48 of LRA Table 3.1-1. They are referred to as "Core Shroud and Core Plate (Core Plate Bolts)." These are the same components as the core plate rim hold down bolts that are referred to on page B-82 of the application.
>
> 2. BSEP has performed a plant-specific evaluation and determined that a minimum of forty-eight core plate rim hold-down bolts are required for BSEP in order to resist seismic shear loads and maintain minimum safety margins. This quantity of bolts applies for the case of *intact but un-preloaded bolts* (emphasis added), and is independent of accumulated fluence level.
>
>   Since the core plate rim hold down bolts can perform their intended function without the benefit of preload and independent of accumulated fluence, loss of preload due to stress relaxation does not require aging management. This was the basis for the response to Applicant Action Item 4 to BWRVIP-25 which states on page B-82 of the LRA:

> Susceptibility of the rim holddown bolts to stress relaxation was evaluated as a potential TLAA, but no TLAA was identified.

The applicant's response to RAI 4.2.8-1, Part B, indicated that the core plate rim hold-down bolts referred to in the RAI are the same components as the "Core Shroud and Core Plate (Core Plate Bolts)" identified and evaluated within the scope of the AMRs listed in LRA Table 3.1.2-1 and referred to on page B-82 of LRA Section B.2.28. In the applicant's response to RAI 4.2.28-1, Part B, the applicant also stated that the integrity of 48 intact but un-preloaded core plate rim hold-down bolts is necessary to maintain the integrity of the core plate, but clarified that the integrity of the bolts does not require maintenance of an adequate preload on the bolts and, therefore, is not dependent on an evaluation of the impact of accumulated neutron fluence level on the preload level. Based on the applicant's response to RAI 4.2.28-1, Part B, the staff found that the applicant does not need to include a TLAA for the core plate rim hold-down bolts because the structural integrity of the bolts does not rely on maintenance of an adequate pre-load. Based on this assessment, RAI 4.2.28-1, Part B, is resolved, and the applicant does not need to include a TLAA on stress relaxation of the core plate rim hold-down bolts.

4.2.8.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the applicant's TLAA for the core plate plugs:

> A.1.2.1.7 Core Plate Plug Spring Stress Relaxation
>
> BSEP Unit 2 has installed mechanical-type core plate plugs in the bypass flow holes of the core support plate. The spring-loaded plugs were designed to withstand typical and worst-case transient differential pressures. However, the spring that provides preload to the core plate plug is expected to relax as a function of thermal and neutron exposure. The loss of preload may cause the plug to leak at a higher rate than the designed. The projected relaxation is based upon 40-year fluence values. Since the spring relaxation would exceed acceptable limits if exposed to a 54 EFPY fluence value, projecting the analysis for 60 years is not feasible. Therefore, loss of pre-load due to stress relaxation of the core plate plug spring will be managed programmatically by means of the Reactor Vessel and Internals Structural Integrity Program.

In RAI 4.2.8-2, Part A, dated April 8, 2005, the staff stated that the applicant's UFSAR supplement summary description for this TLAA discusses the applicant's intent to use the RV&ISIP as its basis for managing loss of preload/stress relaxation in the core plate plugs. The applicant has also included this aging management strategy as a commitment in Enclosure 1 of BSEP Serial Letter No. BSEP-04-006, dated October 18, 2004. In this serial Letter, CP&L submitted the LRA onto Docket Nos. 50-325 and 50-324 for the BSEP and included Enclosure 1 as the initial commitment tracking list (CTL) for the application. In the CTL, the applicant indicated that this commitment for managing loss of preload/stress relaxation in the Unit 2 spring-loaded core plate plugs has been incorporated into the UFSAR supplement summary descriptions for both the TLAA on core plate plugs (LRA Section A.1.2.1.7) and the Reactor Vessel and Internals Structural Integrity Program (Section A.1.1.30). However, the staff determined that the commitment on management of loss of preload/stress relaxation in the Unit 2 spring-loaded core plate plugs has not yet been incorporated into the UFSAR supplement summary descriptions in LRA Sections A.1.2.1.7 and A.1.1.3.0. Therefore, the staff requested that this commitment be incorporated into these UFSAR supplement summary description sections. In Part B of the RAI, the staff requested an editorial modification of an incomplete sentence in the UFSAR supplement summary description.

In its response, by letter dated May 4, 2005, the applicant states:

> **RAI 4.2.8-2 Response**
>
> As stated in the response to RAI 4.2.8-1, the core plate plugs will be replaced at the end of their qualified life by using AMP B.2.28, Reactor Vessel and Internals Structural Integrity Program described on page B-74 of the LRA.
>
> **Part A.** The scope of the commitment for "Time Limited Aging Analysis (TLAA) – Core Plate Plug Spring Stress Relaxation" specifically states:
>
> > Management of Core Plate Plug Spring Stress Relaxation will be performed by means of the Reactor Vessel and Internals Structural Integrity Program.
>
> This line references Sections A.1.2.1.7 and A.1.1.30 of the LRA. Section A.1.2.1.7 of the USFAR Supplement Summary does contain the commitment to manage these components using the Reactor Vessel and Internals Structural Integrity Program as follows:
>
> > Therefore, loss of pre-load due to stress relaxation of the core plate plug spring will be managed programmatically by means of the Reactor Vessel and Internals Structural Integrity Program.
>
> Section A.1.1.30 does contain the summary description of the Reactor Vessel and Internals Structural Integrity Program and does not require listing the specific components managed and associated aging effects.
>
> Nuclear Energy Institute (NEI) letter from A. P. Nelson to P. T. Kuo, USNRC, "Industry Response — Consolidated List of Commitments for License Renewal, December 16, 2002," dated February 26, 2003, stated:
>
> > The industry has agreed to identify the high level future commitments in their (U)UFSAR supplement (Appendix A of the LRA). Examples of what is meant by 'high level' can be seen in the enclosures.
>
> Therefore, no changes are required.
>
> **Part B.** BSEP will correct the UFSAR supplement Summary description in LRA, Appendix A, Section A.1.2.1.7, to revise the sentence to state:
>
> > The loss of preload may cause the plug to leak at a higher rate than designed.

The applicant's UFSAR supplement summary description for the TLAA on the core plate plugs and the applicant's response to RAI 4.2.8-2, Part A, indicate that the applicant has already provided a commitment to use the RV&ISIP as the basis for dispositioning this TLAA and for managing stress relaxation in the BSEP spring-loaded core plate plugs during the period of extended operation. The staff confirmed that the applicant included this commitment in Enclosure 1 to CP&L Serial Letter BSEP 04-0006, dated October 18, 2004. The staff evaluated the RV&ISIP in SER Section 3.0.3.3.1. The staff's evaluation includes an evaluation of the ability of the RV&ISIP to manage stress relaxation in the BSEP spring-loaded core plate plugs and resolution of RAI B.2.28-15, which, in part, addressed the need to amend the UFSAR supplement summary description for the RV&ISIP and specifically addressed how the AMP would be implemented to manage stress relaxation in the BSEP spring-loaded core plate plugs. Since the LRA includes a commitment to use the RV&ISIP as the basis for managing stress relaxation in these core plate plugs and since the ability of the AMP to manage stress relaxation in the core plate plugs is being addressed through the staff's review of the UFSAR supplement summary description for the RV&ISIP (refer to LRA Section A.1.1.30), the staff found that it would be redundant to have to include this type of supplemental information again in the UFSAR supplement summary description for this TLAA, as given in LRA Section A.1.2.2.7. Based on this assessment, the staff found that the UFSAR supplement summary description is acceptable as written and satisfies 10 CFR 54.21(d). RAI 4.2.8-2, Part A is resolved.

RAI 4.2.8-2, Part B identifies a grammatical error in the UFSAR supplement summary description and is an editorial RAI. The applicant's response to RAI 4.2.8-2, Parts B, provided above, corrects the grammatical omission on the UFSAR supplement summary description and is resolved.

4.2.8.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the core plate plug spring stress relaxation TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the core plate plug spring stress relaxation TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.9 Core Shroud Repair Hardware Analysis

In LRA Section 4.2.9, the applicant concluded that the core shroud repair hardware analysis met the definition of a TLAA as defined in 10 CFR 54.3. Henceforth this TLAA will be referred to as the "TLAA for the Core Shroud Repair Clamps" because the hardware utilizes repair clamp assemblies (i.e., bolted bracket assemblies).

4.2.9.1 Summary of Technical Information in the Application

The applicant provided the following assessment for the TLAA for the core shroud repair clamps in LRA Section 4.2.9:

> **4.2.9 CORE SHROUD REPAIR HARDWARE ANALYSIS**
>
> **Summary Description**
>
> In 1994, twelve bolted clamps were installed on the BSEP Unit 1 core shroud to structurally replace the H2 and H3 horizontal welds due to the cracking that had been discovered in these welds. Identical clamps were subsequently installed on the Unit 2 core shroud. The repair hardware is subject to loss of material properties due to neutron irradiation. The hardware design accounted for material property loss through the end of the current 40-year license period. The purpose of the repair hardware is to structurally replace the H2 and H3 welds at the upper end of the core shroud. Twelve repair bracket assemblies were spaced equally around the circumference of the shroud (i.e. one every 30° of circumference). The top guide support ring is "straddled" by the repair block fixture, and the upper and lower shroud assemblies are effectively "clamped" together. A repair bracket consists of a block that is bolted to the lower shroud by two stepped bolts. The block is also bolted to the upper shroud by two additional stepped bolts. Washers are used at each of the upper bolt locations to ensure intimate contact occurs as a result of bolt preload between the contacting surfaces of the repair bracket and the shroud.

Analysis

The design specification for the repair hardware specifies that the maximum neutron radiation flux at the shroud repair clamp is 1.0E13 neutrons/cm^2-sec. It also specifies that the shroud repair clamps shall be designed for a life of 23 years, which was equal to the remaining portion of the 40-year design life of the plant. The cumulative neutron fluence for the design life of the clamp equals the flux multiplied by the time. This results in a design fluence of 7.26E+21 n/cm^2.

The neutron fluence calculation discussed in Subsection 4.2.1 includes fluence projections applicable for the reactor vessel and internals for the current operating term and at 54 EFPY, which bounds 60 years of operation. The calculation includes fluence projections for the reactor pressure vessel and for the core shroud. Separate projections were included for each of the horizontal core shroud welds, which are numbered from H1 at the top of the shroud through H7 near the bottom. The core shroud repair clamps are located in the region of welds H2 and H3. Weld H4 is located approximately 3 feet below these welds, and is nearer the active core of the vessel. Therefore, the H4 location is exposed to higher neutron fluence values than the H2 and H3 welds nearest the clamps. The peak fluence values for the H4 welds were selected as bounding fluence values for the shroud repair brackets. The following data were obtained for the H4 weld locations in each Unit:

Peak Unit 1 54 EFPY Fluence at the H4 Weld location = 4.16E+21 n/cm^2
Peak Unit 2 54 EFPY Fluence at the H4 Weld location = 4.17E+21 n/cm^2

Therefore, the derived design end-of-life fluence value of 7.26E+21 n/cm^2 bounds both the Unit 1 peak fluence value of 4.16E+21 n/cm^2 and the Unit 2 peak fluence value of 4.17E+21 n/cm^2 with considerable margin. Therefore, the core shroud repair hardware analysis remains valid since the hardware design accounted for material property loss resulting from neutron exposure that bounds the neutron exposure projected for the 60-year extended operating period.

Disposition: 10 CFR 54.21(c)(1)(i) – The core shroud repair hardware analyses remain valid through the end of the period of extended operation.

4.2.9.2 Staff Evaluation

Regulatory Evaluation. In 1993 and 1994, the NRC issued two INs on the topic of IGSCC of BWR core shrouds:

- IN 94-42, "Cracking In The Lower Region of the Core Shroud In Boiling Water Reactors," issued on June 7, 1994.

- IN 93-79, "Core Shroud Cracking at Beltline Region Welds in Boiling Water Reactors," issued on September 30, 1993.

The regulatory events discussed in these INs prompted the NRC to issue GL No. 94-03, “Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors,” on July 25, 1994. In this GL, the staff discussed the generic safety significance of crack initiation and growth that had occurred in the core shrouds of a number of U.S. BWRs, including the core shrouds at BSEP, Dresden, and Quad Cities nuclear plants. The root cause of the cracking was attributed to intergranular stress corrosion cracking that initiated in heat-affected zones of the structural welds. In GL 94-03, the staff also requested that licensed owners of BWR facilities perform augmented inspections and analyses of their core shroud structures and make contingency plans for repairing their core shroud structures. The safety significance of the core shroud cracking events summarized in GL 94-03 induced a number plants to implement repair modifications of their core shroud structures, including BSEP. CP&L’s response to GL 94-03 was “docketed” in CP&L Serial Letter No. BSEP 94-0335, dated August 24, 1994.

The most recent basis for managing cracking in BWR core shrouds is given in EPRI Topical Report No. TR-114232-NP, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines (BWRVIP-76),” which was submitted by the BWRVIP to the NRC Document Control Desk on February 29, 2000. Chapter 3 of the report provides the BWRVIP’s recommended aging management strategies for managing crack initiation and growth in core shrouds that have already experienced cracking and have been repaired by design modifications of their core shroud structures.

In RAI 4.2.9-1, Part A, dated April 8, 2005, the staff requested that the applicant identify the plant-specific safety analysis evaluation/document that contains the design-basis safety assessment for installing and maintaining the core shroud repair clamps. The applicant provided its response by letter, dated May 4, 2005, the applicant indicated that CP&L’s response to GL 94-03 is docketed in CP&L Serial Letter No. BSEP 94-0335, dated August 24, 1994. The response to the RAI also indicated that the NRC’s approval of the BSEP core shroud repair clamp design was given in the NRC’s safety evaluation to the applicant dated January 14, 1994, and that the staff’s approval of the applicant’s response to GL 94-03 was approved in the NRC’s safety evaluation dated January 3, 1995. These correspondence letters from the applicant and NRC safety evaluations provide the regulatory basis for approval and installation of the core shroud repair clamps at BSEP. Therefore, the staff’s concern described RAI 4.2.9-1, Part A, is resolved.

Technical Evaluation. In 1994, CP&L implemented repairs of the BSEP core shroud in order to correct the cracking detected in the structures. The repairs involved installation of 12 core shroud repair clamps around the H2 and H3 core shroud welds in each unit. The core shroud repair clamps are bolted connections that were installed to assume the loading in the upper regions of the core shrouds in lieu of the H2 and H3 shroud welds. In RAI 4.2.9-1, Part B, the staff requested confirmation that current core shroud repair designs for BSEP use core shroud repair clamps.

The applicant provided its response to RAI 4.2.9-1, Part B, by letter dated May 4. 2005. In its response, the applicant confirmed that the core shroud repair clamps are the current design assemblies for the BSEP core shroud repair hardware and that tie rod assemblies are not currently used as repair designs for the BSEP core shrouds. Therefore the staff’s concern described in RAI 4.2.9-1, Part B, is resolved.

The design-basis analysis indicated that the core shroud repair clamps were designed to be acceptable for the remaining life of the reactor, as assessed from the time of repair clamp installation (i.e., for a remaining service life of 23 EFPY). The design-basis analysis included an assessment on the impact that neutron radiation would have on the design life of the core shroud repair clamps. The analysis established a maximum limit of 7.26×10^{21} n/cm^2 ($E > 1.0$ MeV) on the amount of neutron radiation that could occur in the core shroud repair clamps during their service lives.

In order to extend the service lives of the core shroud repair clamps, the applicant determined that it was appropriate to treat the design-basis analysis for the core shroud repair clamps as a TLAA for the LRA. The staff found that this is consistent with the NRC’s definition of a TLAA in 10 CFR 54.3, because neutron radiation exposure is a time-limited parameter being used in determining the continued acceptability of the core shroud repair clamps and because the design life for the core shroud repair clamps was assessed for the duration of the current operating periods for BSEP, as assessed from the time of installation. The staff, therefore, agreed that the design-basis analysis for the core shroud repair clamps is required to be treated as a TLAA in accordance with 10 CFR 54.3.

The applicant's basis for accepting the TLAA on the core shroud repair clamps is that the design-basis analysis for the core shroud bracket assemblies remains bounding for the period of extended operation for BSEP. In the BSEP core shroud design, the H2 and H3 core shroud welds are located above the beltline region of the reactor. The H4 core shroud welds are the welds that are located within the beltline region of the reactor. In its neutron fluence assessment for the core shroud repair clamps, the applicant conservatively used the 54 EFPY neutron fluences for the H4 core shroud welds as its basis for projecting the neutron fluences for the H2 and H3 welds to 54 EFPY. This is acceptable because the H4 welds are located in the beltline regions of the reactors and, hence, the neutron fluences associated with the H4 weld locations are bounding for the H2 and H3 weld locations. The applicant calculated the neutron fluences for the BSEP H4 core shroud welds at 54 EFPY using the neutron fluence methodology that was approved by the staff in SER Section 4.2.1.2. The applicant projected the neutron values for the H4 welds to be 4.17×10^{21} n/cm^2 (E > 1.0 MeV) for Unit 1 and 4.16×10^{21} n/cm^2 (E > 1.0 MeV) for Unit 2, as assessed for 54 EFPY.

The staff found that the TLAA on the core shroud repair clamps is acceptable because the limiting neutron fluences for the BSEP core shroud repair clamps, as projected to 54 EFPY, remain bounded by the limiting neutron fluence that was used to establish the design life of the core shroud repair clamps. Based on this analysis, the staff found that the TLAA for the core plate plugs remains bounding for period of extended operation, as assessed in accordance with 10 CFR 54.21(c)(1)(i).

4.2.9.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the applicant's TLAA for the core shroud repair clamps:

> A.1.2.1.8 Core Shroud Repair Hardware Analysis
>
> In 1994, twelve bolted clamps were installed on the BSEP Unit 1 core shroud to structurally replace the H2 and H3 horizontal welds due to the cracking that had been discovered in these welds. Identical clamps were subsequently installed on the Unit 2 core shroud. The repair hardware is subject to loss of material properties due to neutron irradiation.
>
> An analysis was performed to compare the design neutron fluence of the core shroud repair hardware to the calculated neutron fluence that the hardware would experience at 54 EFPY, which bounds 60 years of operation. Based on the analysis, it was concluded that the derived design end-of-life fluence value of 7.26E+21 n/cm^2 bounds both the peak fluence value of 4.16E+21 n/cm^2 for Unit 1 and the peak fluence value of 4.17E+21 n/cm^2 applicable to Unit 2, with considerable margin. Therefore, the core shroud repair hardware analysis remains valid since the hardware design accounted for material property loss resulting from neutron exposure that bounds the neutron exposure projected for the 60-year extended operating period.

The applicant's UFSAR supplement summary description provides the same technical information and bases for the TLAA as is described in LRA Section 4.2.9. The UFSAR supplement summary description also indicates that the neutron fluence used in design-basis analysis for the core shroud repair clamps bounds the neutron fluences that are projected to occur in the core shroud repair clamps at 54 EFPY. Based on this summary description, the staff found that the UFSAR supplement summary description has sufficient information to indicate why the TLAA for the core shroud repair clamps remains valid for the period of extended operation, as consistent with the criterion of 10 CFR 54.21(c)(1)(i), and that the UFSAR supplement summary description is acceptable and is in compliance with 10 CFR 54.21(d).

4.2.9.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the core shroud repair hardware analysis TLAA, the analyses remain valid for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the core shroud repair hardware analysis TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.10 RV Reflood Thermal Shock Analysis

In the applicant’s response to RAI 4.2-2, dated May 4, 2005, discussed in SER Section 4.2, above, the applicant stated that the RV thermal shock analysis for BSEP met the definition of a TLAA as defined in 10 CFR 54.3. Henceforth this TLAA will referred to as the “TLAA on RV Reflood Thermal Shock Analysis.”

4.2.10.1 Summary of Technical Information in the Application

The applicant provided the following description of the TLAA on RV reflood thermal shock analysis in response to RAI 4.2-2:

> The Reactor Vessel thermal shock analysis described in UFSAR 5.3.3.1.3 has been determined to meet the definition of 10 CFR 54.3 for TLAAs. The evaluation of this TLAA is shown in the following paragraphs.
>
> **Summary Description**
>
> Section 5.3.3.1.3 of the USFAR includes an end-of-life (i.e., 40-year) thermal shock analysis performed for the reactor vessel for a design basis LOCA followed by a low-pressure coolant injection. The reflood shock refers to the stress imposed upon the reactor vessel due to contact between the hot vessel shell and the cold water injected to reflood the vessel. The UFSAR states:
>
> > A detailed reactor vessel thermal shock analysis was performed on a representative GE BWR reactor vessel. The thermal shock analysis simulating ECCS-LOCA operation was performed on a reactor vessel design similar to the vessel for this facility and was reported in a GE Topical Report submitted to the AEC in July 1969.
>
> This General Electric (GE) report indicated that a single recirculation line break event could be tolerated at the end of the 40-year design life because the effect of neutron irradiation or other normal service fatigue damage is not expected to appreciably affect the single event tolerable strains.
>
> Since the material properties were based upon 40-year fluence values, they meet the requirements of 10 CFR 54.3(a). As such, the analysis based upon these properties is a TLAA.
>
> **Analysis**
>
> For the current operating period, a thermal shock analysis was originally performed on the reactor vessel components for a standard design. The analysis assumed a design basis LOCA followed by a

low-pressure coolant injection accounting for the full effects of neutron embrittlement at the end-of-life (i.e., 40 years). The analysis showed that the total maximum vessel irradiation at the mid-core inside of the vessel to be 2.4E+17 n/cm^2, which was below the threshold level of any nil-ductility temperature shift for the vessel material. As a result, it was concluded that the irradiation effects on all locations of the reactor vessels could be ignored. However, this analysis only bounded 40 years of operation.

Disposition: Revision, 10 CFR 54.21(c)(1)(ii)

The original analysis has since been superseded by a 40-year analysis for BWR/6 reactor vessels: "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Ranganath, S., Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979, Paper G1/5. The reactor vessels at BSEP are BWR/4. The BWR/6 evaluation determined the maximum stress intensity in the vessel wall as a function of vessel wall thickness and time after the Design Break LOCA. As shown in Figure G2214-1 of ASME Section XI, Appendix G, 1998 Edition through 2000 Addenda, the stress intensity is a function of vessel wall thickness. The original analysis used a recirculation line break, while the BWR/6 analysis was based on a main steam line break event, which is considered to bound the recirculation line break. In addition, the BWR/6 analysis used a vessel thickness similar to that of the BSEP vessels.

Therefore, the BWR/6 analysis is considered applicable to the BSEP reactor vessels, and is considered to be a revised analysis for License Renewal. This BWR/6 analysis assumes 40-year, end-of-life material toughness, which in turn depends on end-of-life-adjusted reference temperature (ART). The critical location for the fracture mechanics analysis is at ¼ of the vessel thickness (i.e., from the inside, ¼T). For this event, the peak stress intensity occurs at approximately 300 seconds after the LOCA. The analysis shows that at 300 seconds into the thermal shock event, the temperature of the vessel wall at 1.5 inches deep, which is ¼T, is approximately 400°F.

The worst-case calculated ART resulting from 54 EFPY radiation exposure (i.e., 60 years) was determined to be 136.1°F, which is well below the 400°F ¼T temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the BSEP reactor vessels are qualified through the end of the period of extended operation.

This TLAA has been projected to the end of the period of extended operation, using Method (ii) of 10 CFR 54.21(c)(1).

4.2.10.2 Staff Evaluation

Regulatory Evaluation. UFSAR Section 5.3.3.1.3 provides the original regulatory basis for the RV reflood thermal shock analysis. In this section of the UFSAR, the applicant provided its dynamic system analysis of the BSEP RV shells under faulted conditions. In the UFSAR section, the applicant identified that the most severe thermal shock event for the BSEP RVs results from flooding by the ECCS as a result of initiation of the systems following occurrence of a postulated the post-design-basis accident. The analysis discussed in UFSAR Section 5.3.3.1.3 is a plant-specific analysis. The analysis discusses how the peak strains in the RVs are acceptable for the 40-year design-basis ASME Code Section III fatigue cycles and the limiting 40-year neutron fluence values for the RVs.

In the response to RAI 4.2-2, the applicant stated that the analysis has been updated and that the new analysis is given in a 40-year analysis for BWR/6 reactor vessels: "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Ranganath, S., Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979, Paper G1/5. The applicant applies this analysis as the latest RV reflood thermal shock analysis for BSEP.

Technical Evaluation. The BSEP RV reflood thermal shock analysis is not mandated by current NRC requirements. However, in its response to RAI 4.2-2, the applicant confirmed that the original

RV reflood thermal shock analysis discussed in UFSAR Section 5.3.3.1.3 is a TLAA as defined in 10 CFR 54.3. The BSEP nuclear units are BWR-4 model light-water reactors. In the original RV reflood thermal shock analysis, the applicant stated that the limiting RV shell reflood event for BSEP units was identified as a design-basis recirculation line break followed by reflooding of the RV as a result of initiation of the LPCI system. The applicant stated that the original analysis demonstrated that the maximum neutron fluence for the RV at EOL (i.e., 40-years of license life) was 2.4 x 10^{17} n/cm^2 (E > 1.9 MeV) and therefore concluded that any impact of the event on the stress intensities for the BSEP were minor because the fluence levels are only slightly higher than the threshold of 1.0 x 10^{17} n/cm^2 (E > 1.9 MeV) for loss of fracture toughness in ferritic RCPB materials (refer to 10 CFR Part 50, Appendix H, as the basis for this threshold value).

GE's generic updated RV reflood thermal shock analysis forms the current CLB of interest for BSEP. In this analysis, GE concluded that RV thermal shock reflood analysis for a BWR-6 model light-water reactor is the bounding RV reflood thermal shock analysis for the U.S. BWR fleet of light-water reactors and identified that the limiting RV reflood thermal shock event is a postulated non-isolable main steam line break followed by ECCS initiation. In this analysis, GE applied the fracture mechanics criteria of Appendix G of Section XI of the ASME Boiler and Pressure Vessel Code (Appendix G to Section XI) and stated that the critical location in the RV, from a fracture mechanics perspective, is that for the 1/4T location of the RV at the beltline region of the RV shell. In this analysis, consistent with the methodology of Appendix G to Section XI, GE determined that the maximum stress intensity in the RV occurs at approximately 300 seconds following onset of the LOCA and that the limiting temperature of the RV at the 1/4T location of the shell will be approximately 400 EF after 300 seconds has elapsed into the event.

The applicant stated that it considers GE's generic RV reflood thermal shock analysis to be applicable to the RV because the size of main steam lines are approximately the same size as those for the limiting BWR-6 light-water reactor assessed in the analysis. To demonstrate that the adjusted reference temperature values (ΔRT_{NDT} values) for RVs have been acceptably projected for the period of extended operation, the applicant must demonstrate that the ΔRT_{NDT} values for the limiting materials in the BSEP RVs at the 1/4T location of the vessels, as projected using the 54 EFPY neutron fluence values (in n/cm^2, E > 1.0 MeV), will be less than 400 EF, as described in the GE analysis. In its response to RAI 4.2-2, the applicant concluded that the 54 EFPY 1/4T ΔRT_{NDT} values for the limiting materials in the BSEP RVs are projected to be less than 400 EF, and, therefore, that the RV flood thermal shock analyses for the BSEP RVs are acceptable under the acceptance criterion of 10 CFR 54.21(c)(1)(ii).

The staff evaluated the TLAA on 1/4T ΔRT_{NDT} values in SER Section 4.2.3. In its evaluation, the staff determined that the applicant's calculation of the 54 EFPY 1/4T ΔRT_{NDT} values for the BSEP RVs was done in conformance with the recommended methods of RG 1.99, Revision 2, and, therefore, that the 54 EFPY 1/4T ΔRT_{NDT} values were acceptable. In the applicant's TLAA on 1/4T ΔRT_{NDT} values, as discussed in LRA Section 4.2.3, the applicant projected that the limiting 54 EFPY 1/4T ΔRT_{NDT} value for Unit 1 will be 136.1 EF at 54 EFPY and that the limiting 54 EFPY 1/4T ΔRT_{NDT} value for Unit 2 will be 125.1 EF at 54 EFPY. Since these values are less than 400 EF, the staff found that applicant has acceptably projected 1/4T ΔRT_{NDT} values for the RVs through the period of extended operation and that the BSEP RVs will continue to have significant margins of safety against the consequences of a RV reflood thermal shock event during the period of extended operation. Based on this assessment, the staff found that the applicant's response to RAI 4.2-2 is acceptable. Thus RAI 4.2-2 is resolved. TLAA on RV reflood thermal shock analysis is acceptable under 10 CFR 54.21(c)(1)(ii).

4.2.10.3 UFSAR Supplement

Section 54.21(d) of 10 CFR requires the UFSAR supplement for a facility LRA to contain a summary description for each AMP and TLAA proposed for aging management. The applicant provided the following UFSAR supplement summary description for the TLAA on RV reflood thermal shock analysis in its supplemental response, dated June 14, 2005, to RAI 4.2-2,:

> A.1.2.1.9 Reactor Vessel Reflood Thermal Shock Analysis
>
> For the current operating period, a thermal shock analysis was originally performed on the reactor vessel components for a standard design. The analysis assumed a design basis Loss of Coolant Accident (LOCA) followed by a low-pressure coolant injection accounting for the full effects of neutron embrittlement at the end-of-life, i.e., 40 years. The analysis showed that the total maximum vessel irradiation, with E \$ 1 MeV, at the mid-core inside of the vessel was 2.4×10^{17} n/cm^2, which was below the threshold level of any nil-ductility temperature shift for the vessel material. As a result, it was concluded that the irradiation effects on all locations of the reactor vessels could be ignored. However, this analysis only bounded 40 years of operation.
>
> For License Renewal, the original analysis has since been superseded by a 40-year analysis for BWR/6 reactor vessels: "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Ranganath, S., Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979, Paper G1/5. The reactor vessels at BSEP are BWR/4. The BWR/6 evaluation determined the maximum stress intensity in the vessel wall as a function of vessel wall thickness and time after the design basis LOCA. As shown in Figure G2214-1 of ASME Section XI, Appendix G, 1998 Edition through 2000 Addenda, the stress intensity is a function of vessel wall thickness. The original analysis used a recirculation line break, while the BWR/6 analysis was based on a main steam line break event, which is considered to bound the recirculation line break. In addition, the BWR/6 analysis used a vessel thickness similar to that of the BSEP vessels.
>
> Therefore, the BWR/6 analysis is considered applicable to the BSEP reactor vessels, and is considered to be a revised analysis for License Renewal. The BWR/6 analysis assumes 40-year end-of-life material toughness, which in turn depends on end-of-life adjusted reference temperature. The critical location for the fracture mechanics analysis is at ¼ of the vessel thickness from the inside (i.e., ¼T). For this event, the peak stress intensity occurs at approximately 300 seconds after the LOCA. The analysis shows that, at 300 seconds into the thermal shock event, the temperature of the vessel wall at 1.5 inches deep, which is ¼T, is approximately 400°F.
>
> The worst-case calculated adjusted reference temperature resulting from 54 EFPY radiation exposure (i.e., 60 years) was determined to be 136.1°F, which is well below the 400°F ¼T temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the BSEP reactor vessel reflood thermal shock analysis has been projected to the end of the period of extended operation.

The applicant's UFSAR supplement summary description for the TLAA on RV reflood thermal shock analysis is identical to the description of the TLAA provided in the applicant's response to RAI 4.2-2, dated May 4, 2005. The summary description demonstrates why the limiting ΔRT_{NDT} value for the BSEP RVs, as projected to 54 EFPY, remains below the 400EF maximum acceptance criterion for the reflood thermal shock analysis and, therefore, why the TLAA is acceptable under 10 CFR 54.21(c)(1)(ii). The staff found that the UFSAR supplement summary description provides a sufficient basis for demonstrating why the TLAA is acceptable under 10 CFR 54.21(c)(1)(ii) is acceptable, pursuant to 10 CFR 54.21(d).

4.2.10.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the RV reflood thermal shock analysis TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the RV reflood thermal shock analysis TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

A metal component subjected to cyclic loading at loads less than the static design load may fail due to fatigue. Metal fatigue of components may have been evaluated based on an assumed number of transients or cycles for the current operating term. The validity of such metal fatigue analysis is reviewed for the period of extended operation. The GALL Report identifies fatigue aging related effects that require evaluation as possible TLAAs, pursuant to 10 CFR 54.21(c). Each of these is summarized in the SRP-LR and presented in LRA Section 4.

4.3.1 Reactor Vessel Fatigue Analyses

4.3.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.1, the applicant summarized the evaluation of the reactor vessel fatigue analyses for the period of extended operation. The original RPV stress report included fatigue analyses for the RV components based on a set of design-basis transients and duty cycles, listed in LRA Table 4.3-1. The fatigue analyses were prepared in accordance with the ASME Code, Section III, 1965 Edition, with Addenda through Summer, 1967, for Class A vessels. The fatigue analysis of the reactor vessel main closure flange was performed to the 1968 Edition of the Code. Since the original design, modifications have been made to replace a number of components, resulting in updated fatigue analyses. The safe ends and thermal sleeves for certain RPV nozzles were replaced, including those for the core spray nozzles, the recirculation inlet nozzles, and the feedwater nozzles (Unit 1 only). The RPV nozzle forgings were not replaced. A revised method of tensioning the reactor head closure bolts with fewer passes has also been developed, and a revised fatigue analysis was prepared. Also, a power uprate to 105 percent of original licensed thermal power was implemented for each BSEP unit, which increased RPV temperature and pressure, resulting in increased fatigue usage. Revised fatigue analyses were performed on limiting components to account for these modifications and operational changes, and these updated 40-year design CUF values are listed in LRA Table 4.3-2.

4.3.1.2 Staff Evaluation

In LRA Section 4.3.1, the applicant listed the reactor vessel components for which metal fatigue TLAAs were identified in the original BSEP stress report, in accordance with the provisions of 10 CFR 54.3(a). The fatigue analyses were based on the design transients listed in LRA Table 4.3-1 and the ASME Code Section III design fatigue strength curves. These components and the corresponding bounding 40-year CUFs were listed in LRA Table 4.3-2. A number of components required revised fatigue analyses as a result of power uprate and other modifications and operational changes, and the updated 40-year design CUFs are also listed in this table. All 40-year CUFs were found to meet the ASME Code Section III limiting value of 1.0 and are, therefore, acceptable. However, five components were found to have CUFs that would have exceeded the limiting value of 1.0 before the end of the period of extended operation. For these components, the applicant made 60-year fatigue usage projections for both units, based on extrapolation of data obtained from the RCPB Fatigue Monitoring Program. This program determines the severity of the transients that actually occur, using a special version of computer software developed for the EPRI. The program monitors plant cyclic data and periodically computes the actual CUF for these components for comparison with the ASME Code Section III limiting value of 1.0. The CUFs thus obtained over a period of time are listed for each unit in LRA Table 4.3.3. The highest projected CUF value for 60 years thus determined is listed as 0.80. The staff found this procedure acceptable since it conforms with current industry practice.

In RAI 4.3-1, dated April 8, 2005, the staff stated that LRA Table 4.3-2 also listed some components as exempted from fatigue analysis. Therefore, the staff requested that the applicant provide justification for exempting these components from a fatigue analysis. In its response, by letter dated May 4, 2005, the applicant indicated that these components were evaluated for fatigue requirements under the rules of ASME Code Section III, Class A Vessels, Paragraph N!415. Under the specified operation of the vessel, the applicant stated that these components met all criteria stated in Paragraph N!415.1, “Vessels not Requiring Analysis for Cyclic Operation,” for exemption from the ASME Code Section III fatigue analysis requirements. The staff found this justification acceptable, since it conforms with the design and fatigue requirements for ASME Code Section III, Class A vessels.

The applicant has committed to manage the fatigue of the vessel components with the potential for exceeding the ASME Code Section III limiting value of 1.0 during the period of extended operation as part of the BSEP Fatigue Monitoring Program, which provides for monitoring stress cycles to ensure that the fatigue CUF limit of 1.0 is not exceeded. The staff found this acceptable because it will provide assurance that the CUFs will not exceed the limiting value for ASME Code Section III Class A vessels to the end of the period of extended operation.

4.3.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel fatigue analyses in LRA Section A.1.2.2.1. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant’s actions to address the reactor vessel fatigue analyses is adequate, because it reflects the information provided in the LRA.

4.3.1.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel fatigue analyses TLAA, the analyses have been projected to the end of the period of extended operation, or that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation, in accordance with pursuant to 10 CFR 54.21(c)(1)(iii). The staff also concluded that the UFSAR supplement contains an adequate summary description of the reactor vessel fatigue analyses TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.2 Reactor Vessel Internals Fatigue Analyses

4.3.2.1 Summary of Technical Information in the Application

In LRA Section 4.3.2, the applicant summarized the evaluation of the reactor vessel internals fatigue analyses for the period of extended operation. The design codes described in LRA Section 4.3.1 did not require a fatigue analysis to be performed for non-pressure boundary RPV internal components. However, the RPV shroud support and RPV internal brackets, which are attached to the pressure-boundary components, were included in the RPV fatigue analyses discussed in LRA Section 4.3.1. The shroud support is specifically identified in LRA Table 4.3-2 and the RPV internal brackets are part of the RPV shell, also shown in that table. The fatigue analyses for these components remain valid through the period of extended operation, in accordance with the discussion in LRA Section 4.3.1. No other fatigue TLAAs were identified for reactor pressure vessel internal components.

4.3.2.2 Staff Evaluation

In RAI 4.3-2, dated April 8, 2005, the staff stated that LRA Section 4.3.2 states that, except for the RPV shroud support and the RPV internal brackets, no other fatigue analyses were identified for the RPV internal components. However, Table 3.1.2-1 lists fatigue analyses of the jet pump assemblies and the fuel support and control rod drive assemblies as TLAAs, evaluated for cumulative damage in accordance with 10 CFR 54.21(c). Therefore, the staff requested that the applicant provide justification for not identifying these TLAAs in LRA Section 4.3.2.

In its response, by letter dated May 4, 2005, the applicant indicated that the reason there are TLAAs for the RPV shroud support and RPV internal brackets is that these components are integral parts of the RPV. They were analyzed for fatigue within the RPV stress report, as required for pressure-retaining components by ASME Code Section III, Class 1 fatigue design rules. The applicant also stated that, using the BSEP AMR methodology, operating temperatures for in-scope components were determined and compared to screening criteria which, if exceeded, indicated that the components are exposed to thermal cycles that may have been analyzed for fatigue. The entries in Table 3.1.2-1, "Cracking due to thermal fatigue," and, "TLAA, evaluated in accordance with 10 CFR 54.21(c)," were applied for each component that exceeded these operating temperature screening criteria. An evaluation was then performed to determine whether or not a fatigue TLAA exists for the component. During the TLAA identification process, the design basis for the RPV internal components was reviewed to determine if fatigue analyses had been performed. No fatigue TLAAs were identified for the jet pump assemblies and the fuel support and control rod drive assemblies.

The staff found the applicant’s response acceptable because it conforms with the criteria stated in 10 CFR 54.3 for the identification of TLAAs. Therefore, the staff’s concern described in RAI 4.3-2 is resolved.

4.3.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of RV internals fatigue analyses in LRA Section A.1.2.2.2. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant’s actions to address the reactor vessel internals fatigue analyses is adequate, because it reflects the information provided in the LRA.

4.3.2.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for the RV internals fatigue analyses TLAA, the analyses remain valid for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the RV internals fatigue analyses TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.3 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)

4.3.3.1 Summary of Technical Information in the Application

In LRA Section 4.3.3, the applicant summarized the evaluation of the effects of reactor coolant environment on fatigue life of components and piping for the period of extended operation, in accordance with the closure of Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." In accordance with interim staff guidance document ISG-16, "Time-Limited Aging Analyses (TLAAs) Supporting Information for License Renewal Applications," the applicant evaluated the environmental effects on 60-year metal fatigue at the high fatigue usage locations listed in NUREG/CR-6260 for older vintage BWR plants.

4.3.3.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.4 pertaining to the effects of reactor coolant environment on the fatigue analysis of components and piping.

GSI-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the reactor coolant system components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The NRC closed GSI-190 in December 1999, concluding that the calculations supporting resolution of this issue, which included consideration of environmental effects and the nature of age-related degradation, indicate the potential for an increase in the frequency of pipe leaks as plants continue to operate. The NRC also concluded that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of reactor coolant environment on component fatigue life as AMPs are formulated in support of license renewal.

The applicant evaluated the component locations listed in NUREG/CR-6260 that are applicable to an older-vintage BWR plant for the effects of the reactor coolant environment on the fatigue life of the components. For each location, detailed 60-year fatigue calculations were performed by applying the appropriate fatigue-environment (F_{en}) relationships from NUREG/CR 6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," for carbon and alloy steels, and those from NUREG/CR 5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," for stainless steel, as appropriate for the material. These calculations showed that the resulting environmentally-adjusted CUFs were all less than 1.0, except for the Unit 1 feedwater nozzle. The applicant performed a refined fatigue analysis and showed that the environmentally-adjusted CUF for this location was also less than 1.0. For all evaluated locations, the highest environmentally-adjusted CUF was 0.982 and, therefore, acceptable because it is less than the ASME Code Section III limiting value of 1.0.

4.3.3.3 UFSAR Supplement

In accordance with 10 CFR 54.21(d), the applicant provided a UFSAR supplement summary description of its TLAA evaluation of effects of reactor coolant environment on fatigue life of components and piping (GSI-190) in LRA Section A.1.2.2.3, Appendix A. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address reactor coolant environmental effects on the fatigue life of components and piping is adequate because it reflects the information provided in the LRA.

4.3.3.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the effects of reactor coolant environment on fatigue life of components and piping TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the reactor coolant environment on fatigue life of components and piping TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.4 Reactor Coolant Pressure Boundary Piping and Component Fatigue Analyses

4.3.4.1 Implicit Fatigue Analysis Design Basis and Methodology

4.3.4.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.4.1, the applicant summarized the evaluation of the implicit fatigue analysis design basis and methodology for the period of extended operation. Other than the RPV, the remaining RCPB components were originally designed in accordance with United States of America Standards (USAS) B31.1-1967, Power Piping Code, which requires implicit fatigue analyses using stress range reduction factors instead of explicit ASME Code Section III, Class 1 fatigue analyses to calculate CUF values. In addition, non-RCPB piping, valves, and components within the scope of license renewal (e.g., main steam piping, pumps and valves, main steam safety/relief valves, and safety valves) were designed in accordance with either the USAS B31.1 or ASME Code Section III, Class C, codes which do not require an explicit fatigue analysis. Instead, these design codes account for cyclic loading by reducing the allowable stress for the component if the number of anticipated cycles exceeds certain limits. It requires the designer to determine the overall number of anticipated thermal cycles for the component and apply stress range reduction factors if this number exceeds 7,000.

4.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.4.1 and evaluated the methodology used by the applicant for determining the fatigue adequacy of piping designed to USAS B31.1. The applicant used the

Unit 2 60-year projected cycles for the RV components listed in LRA Table 4.3-1, since the piping components listed above are generally cycled in parallel with reactor operations. The staff evaluated the applicant's justification for 60-year operation and found it acceptable because it conforms with similar evaluations performed in prior licence renewal applications, and found acceptable by the staff.

4.3.4.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of implicit fatigue analysis design basis and methodology in LRA Section A.1.2.2.4. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address the implicit fatigue analysis design basis and methodology is adequate, because it reflects the information provided in the LRA.

4.3.4.1.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the implicit fatigue analysis design basis and methodology TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the implicit fatigue analysis design basis and methodology TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.4.2 Reactor Vessel Level Instrumentation Condensing Unit Fatigue Analyses

4.3.4.2.1 Summary of Technical Information in the Application

In LRA Section 4.3.4.2, the applicant summarized the evaluation of the reactor vessel level instrumentation condensing unit fatigue analyses for the period of extended operation. In 1994, the RPV level backfill system was installed in each unit to improve the reliability of the water level instrumentation. Since the thermal cycles contributing to fatigue of these components include cycles associated with quarterly testing that do not correlate with reactor vessel transients, this analysis was evaluated separately. ASME Code Section III, Class 1, stress calculations and explicit fatigue analyses were performed during design of the system to document the effects of fatigue for temperature equalizing column instrument piping inside the drywell, including the condensing chambers, steam leg, and reference leg piping. The effects of the 5 percent and 20 percent power uprates have been considered during the license renewal review, and it was concluded that the effects are insignificant relative to the original fatigue analyses. However, the effects from operating the system for the period of extended operation will result in an increased number of thermal cycles, which is evaluated below.

4.3.4.2.2 Staff Evaluation

In LRA Section 4.3.4.2, the applicant evaluated the ASME Code Section III, Class 1, fatigue analyses of the Units 1 and 2 RPV backfill systems for operation to the end of the period of extended operation. The applicant projected the initial 40-year analyses to 60 years of operation, including the effects of 5 percent and 20 percent power uprate, and determined that the highest 60-year CUF, 0.15, will be well below the ASME Code Code Section III, Class 1, limit of 1.0. The staff found this acceptable, because the applicant demonstrated, in accordance with

10 CFR 54.21(c)(1)(ii), that the fatigue analyses of the Units 1 and 2 RPV backfill systems remain valid when projected to the end of the period of extended operation.

4.3.4.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of reactor vessel level instrumentation condensing unit fatigue analyses in LRA Section A.1.2.2.4. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address the reactor vessel level instrumentation condensing unit fatigue analyses is adequate because it reflects the information provided in the LRA.

4.3.4.2.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor vessel level instrumentation condensing unit fatigue analyses TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the reactor vessel level instrumentation condensing unit fatigue analyses TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification

The 10 CFR 50.49 EQ Program was identified as a TLAA for the purpose of license renewal. The TLAA of EQ electrical components includes all long-lived, passive and active electrical and I&C components that are important to safety and located in a harsh environment. Harsh environments within the plant are defined as areas that are subjected to environmental effects by a LOCA or a high-energy line break (HELB). The EQ equipment comprises SR and Q-list equipment; NSR equipment for which the failure could prevent satisfactory accomplishment of any SR function; and the necessary post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant is to provide a list of EQ TLAAs in the LRA. The applicant will demonstrate that one of the following is true for each type of EQ equipment:

- The analyses remain valid for the period of extended operation.
- The analyses were projected to the end of the period of extended operation.
- The effect of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.1 Environmental Qualification of Electrical Equipment

The staff established nuclear station EQ requirements in 10 CFR 50 Appendix A Criterion 4 and 10 CFR 50.49. Section 49 of 10 CFR Part 50 specifically requires that an EQ program be established to demonstrate that certain electrical components located in "harsh" plant environments are qualified to perform their safety function in those environments after the effects of inservice aging. Harsh environments are defined as those areas of the plant that could be subject to the environmental effects of a LOCA, HELB, or post-LOCA radiation. The effects of significant aging mechanisms are required by 10 CFR 50.49 to be addressed as part of an EQ program. For the purpose of license renewal, only those components with a qualified life of 40 years or greater would be TLAAs.

The staff reviewed LRA Section 4.4 in which the applicant described the technical bases and justification for its EQ Program to adequately manage the effects of aging on the intended function(s) of electrical components for the period of extended operation. The staff reviewed this section to determine whether the applicant demonstrated that the effects of aging on the intended function(s) of the electrical equipment will be adequately managed through the EQ Program, together with other programs and processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

4.4.1.1 Summary of Technical Information in the Application

In LRA Section 4.4, the applicant stated that its EQ Program was established to demonstrate that certain electrical components are qualified to perform safety functions in the harsh environment following a design-basis accident. Elements of the proof of qualification involve the original 40-year license period. Therefore, the qualification reports and calculations that comprise the EQ Program meet the definition of a TLAA. In general, the applicant did not establish qualified lives for the components within the EQ Program longer than the original 40-year license period.

Qualified service lives for the EQ components were established and are tracked to determine when a component is nearing the end of its service life. For those components that are nearing the end of their qualified service life, the EQ Program has provisions for the components to be re-evaluated for longer service (i.e., refurbished, requalified, or replaced). Therefore, the TLAAs will be managed by an AMP in accordance with 10 CFR 54.21(c)(1)(iii).

The EQ Program manages thermal, radiation, and cyclical aging of components through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAAs for license renewal. The EQ Program ensures these EQ components are maintained within the bounds of their qualification bases. The applicant has identified thermal, radiation, and cycling aging analyses of plant electrical and I&C components required to meet 10 CFR 50.49 as TLAAs.

The reanalysis of an aging evaluation may be performed to extend the qualification by reducing margin or excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component may be performed as the part of the EQ Program. While a component life-limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, unrealistically low activation energy, or in the application of a component as de-energized instead of energized. As discussed below, the important attributes of reanalysis will include analytical methods, data collection and reduction methods, underlying assumptions, and acceptance criteria and corrective actions (if acceptance criteria are not met).

Analytical Methods. The analytical models used in the reanalysis of an aging evaluation are the same as those applied during the first evaluation. The applicant stated that the Arrhenius methodology is an acceptable thermal model for performing an aging evaluation. The analytical method used for a radiation aging evaluation involves a demonstration of qualification for the total integrated dose (i.e., normal radiation dose for the projected installed life plus accident-radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (i.e., 60 years/40 years). The result is added to the accident-radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods. Reducing excess conservatism in the component service conditions (e.g., temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis. Temperature data used in an aging evaluation are to be conservative and based on plant design temperatures or on actual plant temperature data. Plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as: (1) directly applying the plant temperature data, or (2) using the plant temperature data to demonstrate conservatism when using plant design temperatures. Any changes to material activation energy values as part of a reanalysis are justified on a case-specific basis. Similar methods of reducing excess conservatism in the component service conditions from prior aging evaluations may be used for radiation and cyclical aging.

Underlying Assumptions. EQ component aging evaluations contain sufficient conservatism to account for most environmental changes due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken that may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions. The reanalysis of an aging evaluation could extend the qualification of a component. If the qualification cannot be extended by reanalysis, the component is replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is performed in a timely manner (i.e., sufficient time must be available to maintain, replace, or requalify the component if the reanalysis is unsuccessful).

4.4.1.2 Staff Evaluation

The staff reviewed LRA Section 4.4 to determine whether the applicant submitted adequate information to meet the requirement of 10 CFR 54.21(c)(1). The applicant used 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. The staff reviewed the EQ Program to determine whether it will assure the electrical and I&C components covered under this program will continue to perform their intended functions consistent with the CLB for the period of extended operation. The staff's evaluation of the components' qualification focused on how the EQ Program manages aging effects to meet requirements delineated in 10 CFR 50.49.

The applicant's EQ Program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet 10 CFR 50.49. Qualified life is determined for equipment within the scope of the EQ Program and appropriate actions (i.e., replacement or refurbishment), are taken prior to or at the end of qualified life of the equipment so that aging limits or acceptable margins are not exceeded.

4.4.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation." The applicant provided UFSAR supplement summary description of EQ in LRA Section A.1.2.3. On the basis of its review, the staff concluded the UFSAR supplement summary adequately describes the TLAA on EQ and is, therefore, acceptable.

4.4.1.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the EQ TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the EQ TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d). as required by 10 CFR 54reflected in the license condition..

4.5 <u>Concrete Containment Tendon Prestress</u>

4.5.1 Summary of Technical Information in the Application

The containment structures for Units 1 and 2 have no prestressed tendons. Therefore, this section is not applicable.

4.6 <u>Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis</u>

4.6.1 Torus Downcomer/Vent Header Fatigue Analysis

4.6.1.1 Summary of Technical Information in the Application

In LRA Section 4.6.1, the applicant summarized the evaluation of the torus downcomer/vent header fatigue analysis for the period of extended operation. In 1975, subsequent to the establishment of the original design criteria for the BWR Mark 1 containment system design, additional load conditions were identified which relate to the pressure suppression concept. These additional loads result from the dynamic effects of drywell air and steam being rapidly forced into the suppression pool during a postulated LOCA and from suppression pool response to safety/relief valve (SRV) operation generally associated with plant transient operating conditions. The industry initiated short- and long-term programs to quantify the hydrodynamic loads and restore the originally intended design safety margins. The report, “Plant Unique Analysis Report - Mark 1 Containment Program for Brunswick Units 1 and 2,” provides the results of the long-term program for Units 1 and 2. The vent system structures were evaluated for hydrodynamic loads resulting from postulated LOCA conditions and SRV discharge loads together with dead loads and seismic loads, including fatigue analysis of the limiting locations.

4.6.1.2 Staff Evaluation

In RAI 4.6-1, dated April 8, 2005, the staff requested that the applicant provide the design codes for the liner plate, torus downcomer/vent header and torus-attached piping, and SRV piping. In its response, dated May 4, 2005, the applicant stated that, unlike all other Mark I torus designs, the BSEP torus design utilizes a reinforced concrete structure with a coated carbon steel liner plate. The drywell and suppression chamber (i.e., the torus), including vent line, vent header, and penetrations, are Class I structures, as defined in UFSAR Section 3.2.1.1. The torus liner plate was designed as part of the suppression chamber.

The applicant indicated that the applicable design codes for the reactor containment (i.e., drywell and torus, including extension of drywell), are provided in UFSAR Table 3-9. The design and construction of the portions of the containment not backed by reinforced concrete were in accordance with the applicable requirements specified in Specification 9527-01-15-1, ASME Code Section III (Subsection B), 1968 Edition with Summer, 1968 Addenda, Code Case 1330-1, and Code Case 1177-5. The design and construction of the portions of the containment backed by reinforced concrete were in accordance with the applicable requirements specified in Specification 9527-01-15-1 and ASME Code Section VIII, 1968 Edition with Summer, 1968 Addenda. UFSAR Table 3-9 also indicates that the SRV discharge piping and the various piping systems attached to the torus were originally designed in accordance with ANSI (USAS) B31.1.0, 1967 Edition, Power Piping Code. Additional Codes, standards, and guides, used in the design of the containment and internal structures that resulted from the Mark I Containment Program, are also specified in UFSAR Section 6.2.1.1.2.2. The structural design is based on the 1977 Edition of ASME Code Section III, Subsection ND, Addenda through Summer, 1977, which was also used for defining the containment design margin of safety for the shell, vent header system, and internal structures of the torus, as described in BSEP responses to NUREG-0661, "Mark I Containment Long Term Program Safety Evaluation Report," July 1980. The staff found this response acceptable, because it conforms with standard design codes used for design and construction of nuclear facilities.

The applicant stated that 40-year design fatigue analyses were performed for the downcomer/vent header intersection, because this location was determined as the critical location in the vent system for fatigue damage when subjected to condensation oscillation loads mainly due to SRV actuation and chugging loads. The applicant estimated that 400 SRV actuations would occur over the 40-year plant life, based on the actual RCPB Fatigue Monitoring Program SRV actuations counted through 1981. By assuming 5 cycles per event, the applicant estimated 2000 SRV cycles over 40 years for the design fatigue analyses. On this basis, the highest CUF was calculated as 0.286. For 60-year operation, the applicant projected the number of SRV cycles to 3000 and a design-basis CUF of 0.429. In addition, the applicant also determined a design CUF of 0.15 for the condensation oscillation loads. The largest 60-year design-basis CUF was, therefore, determined as 0.579. The staff found this acceptable, since it is below the ASME Code Section III Class 1 limiting CUF value of 1.0.

In RAI 4.6.1-1, dated April 8, 2005. the staff requested that the applicant to provide a statement indicating that the estimate of the total number of 60-year SRV actuations used in the design fatigue analysis remains valid and conservative, based on the actual SRV actuations counted through 2004. In its response, by letter dated May 4, 2005, the applicant stated that the actual number of SRV actuations and cycles that has been projected for 60-year operation is based indirectly on the number of SRV actuations that occur during plant startups and reactor scrams, and are tracked with the RCPB Fatigue Monitoring Program. Based on this tracking, the applicant stated that the actual projected number of SRV cycles for 60-year operation was 1644. The projected number of 3000 SRV cycles used in the 60-year fatigue design analysis therefore remains valid, and is conservative when compared to the actual number of projected SRV cycles and the fatigue CUF has also been projected to be below the ASME Code Section III Class 1 fatigue limit. The staff reviewed the applicant's response and found it acceptable because it conforms with nuclear industry practice. Therefore, the staff's concern described in RAI 4.6.1-1 is resolved.

4.6.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of torus downcomer/vent header fatigue analysis in LRA Section A.1.2.4.1. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address the torus downcomer/vent header fatigue analysis is adequate, because it reflects the information provided in the LRA.

4.6.1.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the torus downcomer/vent header fatigue analysis TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the torus downcomer/vent header fatigue analysis TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.6.2 Torus-Attached and SRV Piping System Fatigue Analyses

4.6.2.1 Summary of Technical Information in the Application

In LRA Section 4.6.2, the applicant summarized the evaluation of the torus-attached piping and SRV piping system fatigue analysis for the period of extended operation. In August, 1981, the NRC raised a concern regarding the cyclic stresses due to the Mark 1 (containment design) cyclic mechanical loads. The Mark 1 Owners' Group and GE proposed that a method be developed for piping fatigue evaluation and that the method be applied to piping systems representative of the most limiting Mark 1 plants. It was agreed that the fatigue approach should be developed along the lines of the ASME Code Section III, Class 2/3 piping design methods. The loading cycles and loading cycle combinations applicable to the Mark 1 Containment Program load definitions were determined, and an "augmented" Class 2/3 fatigue methodology to account for cyclic mechanical loads was developed. This was used in evaluating representative limiting piping systems for BSEP. The analyses were based on 2,000 cycles for 40 years. Since these results are representative of the most limiting locations for fatigue usage, the remainder of the torus piping systems would have even lower fatigue usage. For license renewal, the 40-year results were projected to 60 years and the CUF was shown to be less than 1.0. Therefore, the fatigue analyses of the torus-attached piping and the SRV discharge piping have been projected to remain valid to the end of the period of extended operation.

4.6.2.2 Staff Evaluation

The applicant stated that the torus-attached piping and SRV piping system design fatigue analyses were based on 2000 cycles for 40-year operation. The largest fatigue CUF of 0.486 was determined in an SRV discharge line under combined normal operating conditions and design-basis accident. For 60-year operation, the applicant conservatively projected the CUF to 0.972, based on doubling the number of cycles, thus showing that it was below the limiting value of 1.0. The staff reviewed the applicant's submittal and found it acceptable, because it conforms with accepted licence renewal practice for fatigue analyses of torus-attached piping and SRV piping systems, as accepted by the staff in prior LRAs.

In RAI 4.6.1-2, dated April 8, 2005, the staff requested that the applicant provide a description or a reference to the "augmented" Class 2/3 fatigue methodology that was developed to account for cyclic mechanical loads. In its response, by letter dated May 4, 2005, the applicant referred to Report MPR-751, "Mark I Containment Program Augmented Class 2/3 Fatigue Evaluation Method and Results for Typical Torus-Attached and SRV Piping Systems, November, 1982;" prepared by MPR Associates, Washington, D.C. for a description of this methodology. A copy of this report was previously submitted to the NRC as Attachment RAI 13 to BSEP letter to the NRC (Serial: LAP-83-416), "Mark I Containment Program Responses to NRC Requests for Information," dated September 15, 1983. The staff at that time reviewed and approved this methodology. The staff, therefore, found the application of this methodology to the license renewal fatigue evaluation of the torus-attached and SRV piping systems acceptable, since it had previously been approved as a response to an RAI on the Mark I Containment Program. Therefore, the staff's concern described in RAI 4.6.1-2 is resolved.

4.6.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of torus-attached and SRV piping system fatigue analysis in LRA Section A.1.2.4.2. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address the torus-attached and SRV piping system fatigue analysis is adequate, because it reflects the information provided in the LRA.

4.6.2.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the torus-attached piping and SRV piping system fatigue analysis TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the torus-attached piping and SRV piping system fatigue analysis TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific Analyses

In LRA Section 4.7, the applicant provided its evaluation of plant-specific TLAAs. The TLAAs evaluated include the following:

- Service Level 1 coatings qualification
- fuel pool girder tendon loss of prestress
- crane refueling platform and monorail hoist cyclic load limits
- torus component corrosion allowance

4.7.1 Service Level 1 Coatings Qualification

4.7.1.1 Summary of Technical Information in the Application

In LRA Section 4.7, the applicant described the analysis of radiation degradation of Service Level 1 coatings that are used inside the primary containment of Units 1 and 2. The applicant considered the coatings to be safety related because they could potentially detach during a design-basis accident (DBA), and the coating debris could contribute to flow blockage of emergency core cooling system suction strainers. The qualification of the coatings to withstand the effects of radiation and the DBA conditions assures that these coatings will remain in place and not contribute to clogging the ECCS strainers beyond analyzed limits.

The original BSEP qualification tests were performed for the coating prior to original plant startup using radiation values necessary to bound 40 years of service and using DBA parameters based upon original licensed thermal power limits. Additional qualifications were performed later to support the use of different brands of coating used for coating repairs and refurbishment from 1994 to the present.

The coatings used for Service Level 1 applications at BSEP were qualified and applied in accordance with the requirements of the following documents:

- USNRC Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," issued June 1973
- ANSI N101.4 – 1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities"
- ANSI N101.2 – 1972, Protective Coatings (Paints) for Light Water Nuclear Containment Facilities"
- ANSI N512 – 1974, "Protective Coatings (Paints) for the Nuclear Industry"

Since it is assumed that the degree of radiation exposure used in the qualification testing was intended to bound 40 years of operation, this evaluation will determine whether or not the radiation exposure used in the qualification tests bounds the projected exposure for 60 years of operation.

The applicant prepared an analysis that provides the design-basis radiation projections for EQ of electrical components. The applicant adjusted the current revision of this EQ analysis to account for previously approved power uprate conditions and the 60-year period of extended operation. The analysis results for the total integrated exposure for 60 years of operation plus the DBA dose is 3.4 x 10^8 rads. This is the worst-case bounding value for primary containment, using the value projected for the torus. If a test coupon has been exposed to this level of radiation or greater, followed by acceptable DBA testing, it will be considered qualified for the 60-year period of operation.

The applicant also reviewed the test reports used to qualify the specific coating types used inside primary containment and determined that the total radiation exposure applied during qualification testing is at least 1.0 x 10^9 rads. The applicant compared the qualified dose values to the worst-case values bounding 60 years of service plus the accident radiation exposure calculated above. On the basis of this comparison, the applicant determined that radiation exposure levels remain valid for the period of extended operation. The applicant concluded that the analyses of qualification of Service Level 1 coatings have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

In LRA Section 4.7.1, the applicant summarized the evaluation of the Service Level 1 coatings qualification for the period of extended operation. Service Level 1 coatings are the coatings used inside the primary containments of Units 1 and 2 that are considered safety related because they could potentially detach during a DBA, and the coating debris could contribute to flow blockage of ECCS suction strainers. The original BSEP qualification tests were performed for the coatings prior to original plant startup using radiation values necessary to bound 40 years of service and using DBA parameters based upon original licensed thermal power levels. Additional qualifications were performed later to support the use of different brands of coating used for coating repairs and refurbishment from 1994 to the present.

4.7.1.2 Staff Evaluation

In accordance with 10 CFR 54.21(c)(1), for each CLB analysis that is identified as a TLAA, the applicant must demonstrate that (1) the analysis remains valid for the period of operation, (2) the analysis has been projected to the end of the period of extended operations, or (3) the effects of aging on the intended function(s) will be adequately managed for the period of extended operations.

The staff reviewed portions of a Nuclear Generation Group calculation, as documented in the Audit and Review Report. The calculation include projected radiation exposure values updated to account for the effects of the 5 percent power uprate, the 20 percent power uprate, and 60-year period of extended operation. The analysis that provided the design-basis radiation projections for EQ of electrical components is described in LRA Section 4.4.2, “EQ Component Reanalysis Attributes.”

The calculation also evaluated the radiation exposures used in the acceptance tests for the different types of qualified coatings. The applicant identified the specific coating types used inside the primary containments of Units 1 and 2, the general locations where the coatings were used, the time frames in which the coatings were applied, and the applicable qualification test reports that contain the radiation levels and temperatures for each test.

The applicant applied Keeler and Long 6548/7107 epoxy primer and topcoat to all carbon steel surfaces inside containment during original construction. The Keeler and Long qualification coupons were exposed to 1.0 x 10^9 Rads.

The staff determined that the radiation exposures used to qualify the coatings (at least 1.0 x 10^9 rads) are greater than the projected radiation exposures over the period of extended operations (3.4 x 10^8 rads). Therefore, the staff determined that the applicant's analysis is acceptable because the analysis has been projected through the end of the period of extended operation.

4.7.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Service Level 1 coatings qualification in Section A.1.2.5 of LRA Appendix A. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address the Service Level 1 coatings qualification is adequate.

4.7.1.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the Service Level 1 coatings qualification TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the Service Level 1 coatings qualification TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.7.2 Fuel Pool Girder Tendon Loss of Prestress

4.7.2.1 Summary of Information in the Application

Two post-tensioned, concrete girders are used to support the spent fuel pool of each reactor building. The concrete girders span the exterior walls of the reactor buildings. Tendons provide the post-tension force for the two concrete girders. The girders support the structure for the fuel pool, steam separator, dryer pool, and reactor well. The tendons are not associated with the pressure boundary type conventional containment post-tensioning system; however, the griders support are safety related structures.

The fuel pool girders are approximately 5 feet wide, 41 feet deep, and 150 feet in length. Each is post-tensioned with 12 pairs of parabolically draped tendons. Each tendon is anchored on the outside (north and south side) of the reactor buildings. The tendons are unbonded and made up of 90 stress-relieved wires contained in a grease-filled conduit. The wires are ¼-inch diameter and meet the ASTM A-421 specification with an ultimate tensile strength of 240 KSI. Grease was used for corrosion protection.

The applicant recognizes that the prestressing force level in the tendons do not remain constant, because of the time-dependent nature of shrinkage and creep of concrete, and relaxation of prestresing tendon elements. The applicant provided the factors it had considered in the original evaluation of the girder tendons.

In the LRA, the applicant explained that elastic shortening of concrete is considered only as an initial loss and will not be increased for the period of extended operation, and notes that this position is consistent with RG 1.35.1. Losses due to concrete shrinkage and creep are time-dependent and decline over time; as such, the 40-year losses have been increased 25 percent to account for the 20-year period of extended operation. Relaxation of steel stress was considered to continue at the same rate as for the first 40 years and was, therefore, increased 50 percent to account for the 20-year period of extended operation. Based on the increased losses during the period of extended operation, the applicant stated that the 60-year prestress value was projected to fall below the minimum required prestress; as such, the TLAA cannot be projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). Therefore, the TLAA will require the alternative method of 10 CFR 54.21(c)(1)(iii) for managing the loss of prestress for the period of extended operation. The applicable aging management program for managing loss of prestress is the Fuel Pool Girder Tendon Inspection Program, which is based on the current periodic testing/inspection program for the girders that was implemented in 1994. The current program includes, among other inspection activities, a load monitoring (lift-off test) of a sample of tendons from each girder. The program uses the guidelines of RG 1.35 and ASME Code Section XI, Subsection IWL, for inservice inspection of containment post-tensioning systems. A frequency of once every five years has been established since the initial inspection having been completed in 1994.

Based on this explanation, the applicant decided to continue lift-off testing of the girder tendons, and to manage the tendon losses pursuant to 10 CFR 54.21(c)(1)(iii). The applicant found that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.7.2.2 Staff Evaluation

The staff notes that though the prestressed concrete containment inservice inspection provisions of RG 1.35 and ASME Code Section XI, Subsection IWL, are not directly applicable to the fuel pool girder tendons, the applicant prefers to use them for inservice inspection of the fuel pool girder tendons. The staff found the approach acceptable, as it will help monitor the tendon forces, as well as the condition of tendon wires, anchorages, and corrosion protection medium.

The applicant computed the minimum required prestressing force values at 60 years by increasing the estimated 40-year creep and shrinkage losses by 25 percent, and wire relaxation losses by 50 percent. The staff believes that, in general, the applicant’s assumptions are adequate; however, depending on the sustained bulk temperatures of water in the spent fuel pools, and on the air temperature in the reactor buildings, the losses due to tendon wire relaxation and creep of concrete could be significantly different. Such effects on tendon forces will be reflected in the tendon lift-off testing. As the applicant plans to perform the lift-off testing every five years during the current license, and during the extended period of operation,as described by the applicant in LRA Section B.2.32, “Fuel Pool Girder Tendon Inspection Program,” and discussed in SER Section 3.0.3.3.5, the staff found the applicant’s approach for performing the TLAA acceptable.

4.7.2.3 UFSAR Supplement

In LRA Section A.1.2.6, “Fuel Pool Girder Tendon Loss of Prestress,” the applicant summarized the time-limited characteristics of the tendon prestressing forces, and noted:

> The prestressing forces generated by the tendons diminish over time due to losses in prestressing forces in the tendons and in the surrounding concrete. The design-basis anchor forces for the tendons were originally based on losses projected for a 40-year period. Additional losses due to the 20-year period of extended operation will analytically reduce the design-basis anchor forces below those required for the tendons to perform

their intended function. Therefore, the TLAA cannot be projected to the end of the period of extended operation; and this analysis relies on an aging management program in accordance with 10 CFR 54.21 (c)(1)(iii) to adequately manage the tendons for the period of extended operation. Thus, the Fuel Pool Girder Tendon Inspection Program will be employed to manage the effects of loss of tendon prestress.

The staff found the summary provided in Section A.1.2.6 adequate and acceptable, as the tendon loss of prestress will be managed by the applicant's AMP B.2.32, "Fuel Pool Girder Tendon Inspection Program." The staff evaluation of the AMP is provided in SER Section 3.0.3.3.5.

4.7.2.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the fuel pool grider tendon loss of prestress TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the fuel pool grider tendon loss of prestress TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.7.3 Crane Refueling Platform and Monorail Hoist Cyclic Load Limits

4.7.3.1 Summary of Technical Information in the Application

In LRA Section 4.7.3, the applicant summarized the evaluation of the crane refueling platform and monorail hoist cyclic load limits for the period of extended operation. The load cycle limits for cranes was identified as a potential TLAA. The following BSEP cranes are within the scope of license renewal and have been identified as having a TLAA, which requires evaluation for 60 years: (1) reactor building cranes, (2) refueling platforms, (3) intake structure crane, (4) diesel generator bridge crane, and (5) miscellaneous monorails/hoists. The method of review applicable to the crane cyclic load limit TLAA involves: (1) reviewing the existing 40-year design basis to determine the number of load cycles considered in the design of each of the cranes in the scope of license renewal, and (2) developing 60-year projections for load cycles for each of the cranes in the scope of license renewal and comparing them with the number of design cycles for 40 years.

4.7.3.2 Staff Evaluation

4.7.3.2.1 Reactor Building Cranes

LRA Section 4.7.3.1 states that the reactor building crane purchasing specification required that the crane conform to the latest edition of CMAA-70 for electric overhead traveling cranes, Service Class A-1; and states that the crane was designed for 20,000 to 100,000 load cycles. The number of load lifts originally projected for the 40 years was 2,500, and the number of load cycles projected for the 60-year life is 3,750. The applicant found that this is less than the 20,000 to 100,000 permissible cycles; therefore, the reactor building crane fatigue analysis has been successfully projected for the 60 years of plant operation.

In LRA Section B.2.9, the applicant stated that the Inspection of Overhead Load and Light Load Handling Systems Program is an existing AMP that, following enhancement, will be consistent with the GALL AMP XI.M23. Element 3 of GALL AMP XI.M23 states that the number and magnitude of lifts made by the crane are also reviewed.

On the basis of a review of the applicant's estimation of the number of load cycles projected for the reactor building crane for 60 years of plant operation, and the applicant's commitment that, consistent with GALL AMP XI.M23, the number and magnitude of lifts made by the crane will be reviewed, the staff found that the reactor building crane analysis has been projected to the end of the period of extended operation.

4.7.3.2.2 Refueling Platforms

LRA Section 4.7.3.2 states that the refueling platform purchasing specification required that the lifting structure be manufactured in accordance with the Manual of Steel Construction. In accordance with the American Institute of Steel Construction (AISC) code, the permissible number of lifts was estimated to be 117,334 cycles. The applicant stated that, based on the refueling operations history, the number of load cycles estimated for the 60-year life is 57,400. The applicant found that 57,400 cycles is fewer than the 117,334 permissible cycles; therefore, the refueling platform fatigue analysis has been successfully projected for the 60 years of plant operation.

In LRA Section B.2.9, the applicant stated that the Inspection of Overhead Load and Light Load Handling Systems Program is an existing AMP that, following enhancement, will be consistent with GALL AMP XI.M23. Element 3 of GALL AMP XI.M23 states that the number and magnitude of lifts made by the crane are also reviewed.

On the basis of a review of the applicant's estimation of the number of load cycles projected for the refueling platform for 60 years of plant operation and the applicant's commitment that, consistent with GALL AMP XI.M23, the number and magnitude of lifts made by the crane will be reviewed, the staff found that the refueling platform analysis has been projected to the end of the period of extended operation.

4.7.3.2.3 Intake Structure Crane

LRA Section 4.7.3.3 states that the intake structure crane purchasing specification required that the crane conform to the latest edition of CMAA-70 for electric overhead traveling cranes, Service Class A-1; and states that the crane was designed for 20,000 to 100,000 load cycles. On the basis of operating maintenance history, the number of load lifts projected for the 60-year life is 2,880. The applicant found that this is fewer than the 20,000 to 100,000 permissible cycles; therefore, the intake structure crane fatigue analysis has been successfully projected for the 60 years of plant operation.

In LRA Section B.2.9, the applicant stated that the Inspection of Overhead Load and Light Load Handling Systems Program is an existing AMP that, following enhancement, will be consistent with GALL AMP XI.M23. Element 3 of GALL AMP XI.M23 states that the number and magnitude of lifts made by the crane are also reviewed.

On the basis of a review of the applicant's estimation of the number of load cycles projected for the reactor building crane for 60 years of plant operation and the applicant's commitment that, consistent with GALL AMP XI.M23, the number and magnitude of lifts made by the crane will be reviewed, the staff found that the intake structure crane analysis has been projected to the end of the period of extended operation.

4.7.3.2.4 Diesel Generator Bridge Crane

LRA Section 4.7.3.4 states that the diesel generator bridge crane purchasing specification required that the lifting structure be manufactured in accordance with the Manual of Steel Construction AISC code which permits up to 10,000 complete stress cycles at maximum stress. The applicant stated that, based on maintenance operating history, the number of load cycles estimated for the 60-year life is 600. The applicant found that 600 cycles is less than the 10,000 permissible cycles; therefore, the diesel generator bridge crane fatigue analysis has been successfully projected for the 60 years of plant operation.

In LRA Section B.2.9, the applicant stated that the Inspection of Overhead Load and Light Load Handling Systems Program is an existing AMP that, following enhancement, will be consistent with GALL AMP XI.M23. Element 3 of GALL AMP XI.M23 states that the number and magnitude of lifts made by the crane are also reviewed.

On the basis of a review of the applicant's estimation of the number of load cycles projected for the diesel generator bridge crane for 60 years of plant operation and the applicant's commitment that, consistent with GALL AMP XI.M23, the number and magnitude of lifts made by the crane will be reviewed, the staff found that the analysis has been projected to the end of the period of extended operation.

4.7.3.2.5 Miscellaneous Monorails/Hoists

LRA Section 4.7.3.5 states that the miscellaneous monorails/hoist purchasing specification required that the lifting structures be manufactured in accordance with the Manual of Steel Construction AISC Code 6th Edition, and the AISC Code permits up to 10,000 complete stress cycles at maximum stress. The applicant stated that the number of load cycles estimated for the 60-year life is 2,100. The applicant found that 2,100 cycles is less than the 10,000 permissible cycles; therefore, the miscellaneous monorails/hoists fatigue analysis has been successfully projected for the 60 years of plant operation.

In LRA Section B.2.9, the applicant stated that the Inspection of Overhead Load and Light Load Handling Systems program is an existing AMP that, following enhancement, will be consistent with GALL AMP XI.M23. Element 3 of GALL AMP XI.M23 states that the number and magnitude of lifts made by the crane are also reviewed.

On the basis of a review of the applicant's estimation of the number of load cycles projected for the miscellaneous monorails/hoists for the 60 years of plant operation and the applicant's commitment that, consistent with GALL AMP XI.M23, the number and magnitude of lifts made by the crane will be reviewed, the staff found that the analyses have been projected to the end of the period of extended operation.

4.7.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of crane, refueling platform and monorail hoist cyclic load limits in LRA Section A.1.2.7. On the basis of its review of the UFSAR supplement, the staff concluded that the summary description of the applicant's actions to address the crane, refueling platform and monorail hoist cyclic load limits is adequate.

4.7.3.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the reactor building crane, refueling platform, intake structure crane, diesel generator cranes and miscellaneous monorails/hoists, refueling platform, intake structure crane, diesel generator cranes and cyclic load limits TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the crane refueling platform and monorail hoist cyclic load limits TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.7.4 Torus Component Corrosion Allowance

4.7.4.1 Summary of Technical Information in the Application

LRA Section 4.7.4, "Torus Component Corrosion Allowance," states that the scope of the TLAA calculation only addresses the corrosion of selected uncoated carbon steel components associated with the torus that were determined by this analysis to have adequate corrosion margin for the remaining life of the plant.

These components are the torus liner, component supports, and miscellaneous torus supports. The component supports are classified as ASME Code Section XI, ISI component supports in the torus and non-ASME Code, Section XI, ISI component supports. The applicant evaluated these components by (1) reviewing the existing 40-year design basis to determine the basis used to evaluate the material loss due to corrosion, (2) developing 60-year projections for the torus components subject to corrosion and comparing the projections with the minimum requirements established for the 40-year service period, and (3) drawing conclusions.

The uncoated areas of the torus liner in the vapor zone of Units 1 and 2 were evaluated by determining a corrosion allowance and applying a corrosion rate. Allowing for a mill tolerance of 0.01-inch, the corrosion allowance available is 0.115 inch. The corrosion rate in the immersion zone was determined to be 0.00116 inch/year based on the results of plant calculations and measurements. The general corrosion rate for the vapor zone is assumed to be the same as that for the immersion zone. Based on the corrosion rate of 0.00116 inch/year, the applicant concluded that the uncoated areas of the torus liner in the vapor zone of Units 1 and 2 are acceptable for the 60-year service period.

The inaccessible ASME Code Section XI, inservice-inspection component supports in the torus of Units 1 and 2 are not coated and evaluated for this TLAA. These uncoated supports are located in both vapor and immersion zones. The evaluation considered the number of sides of the component exposed to the torus environment and the inservice time of the component. The applicant concluded that, based on the corrosion rate of 0.00116 inch/year, the uncoated, inaccessible ASME Code Section XI, inservice-inspection component supports are acceptable for the 60-year service period.

The inaccessible non-ASME Code Section XI, inservice-inspection components in the torus are not coated and evaluated for this TLAA. These uncoated supports are located in both vapor and immersion zones. These components are:

- 6-inch lower column support for the vent header, which is uncoated and located in the immersion and vapor zones
- platform steel components (grating bearing bars, tubular and pipe support members), which are located in the vapor zone
- piping supports for the RHR test line, RCIC turbine exhaust line, RCIC barometric condenser line, RCIC turbine drain pot line, HPCI turbine exhaust line, core spray test line, RHR continuous cooling line (torus spray header), small bore and conduit.

These components were reviewed assuming a corrosion rate of 0.00116 inch/year (determined for components in the immersion zone) and did not meet the minimum thickness requirements for the 60-year service period. Therefore, the applicant proposes a one-time volumetric (ultrasonic) inspection of actual component conditions in the vapor zone to establish a corrosion rate based on service-to-date. The rate of corrosion based on the service-to-date is expected to be considerably less than that for the immersion zone. The lower corrosion rate will then be applied to evaluate a 60-year service period. Results of the volumetric examinations will determine follow-up actions, as needed, such as further examination and/or replacement.

4.7.4.2 Staff Evaluation

The staff reviewed the applicant's evaluation of the uncoated torus liner and torus ASME Code Section XI ISI component supports consistent with 10 CFR 54.21(c)(1)(ii), and the uncoated torus non-ASME Code Section XI, ISI and miscellaneous piping component supports consistent with 10 CFR 54.21(c)(1)(iii).

<u>Torus Liner and Torus ASME, Section XI, ISI Component Supports</u>. Section 54.21(c)(1)(ii) of 10 CFR requires the applicant to project the time-limited aging analyses to the end of the period of extended operation.

In RAI 4.7.4-1, dated March 17, 2005, the staff requested that the applicant provide additional information. The information requested is summarized as follows:

- Inspection requirements and most recent significant inspection results for these components to support the application of the 0.00116 inches/year corrosion rate;
- Details regarding the calculation of the 0.00116 inches/year corrosion rate applied to these components; and
- Details regarding the inspection of the components in the vapor zone to which the 0.00116 inches/year corrosion rate is applied.

In its letter dated March 31, 2005, the applicant responded to the staff's request as summarized below:

- With respect to the most recent significant inspection results, the components within this group are visually examined under examination category E-A, "Containment Surfaces," Subsection IWE of the ASME Code, Section XI. There have been no significant inspection findings and the most recent results indicate a tightly adhering corrosion, scattered rust stains, and mechanical marks.

- Two separate methods were used to determine the corrosion rate applied to the components within this group. The first method utilized ultrasonic tests (UT) of the wall thickness below the water line during the torus modifications completed in the 1980s. The second method evaluated removable corrosion coupons installed on coupon racks at and below the waterline in each unit.

  In 1980, the Unit 2 torus coatings were removed in locations where new structural components were welded to the liner plates. In addition, coatings were also removed from 16 control locations, spaced at equal intervals around the torus, below the waterline. Three UT measurements were taken at each control location.
  Measurements at these locations were repeated in 1982 and 1984. Similar measurements in Unit 1 were completed in 1983 and 1985. A corrosion rate of 0.00105 inches/year was determined from these measurements.

  A Corrosion Monitoring Program was implemented in September 1982, at Unit 2 and in August 1983, at Unit 1. This program evaluated bare carbon steel coupons in accordance with the specifications of ASTM G 4-68, "Standard Recommended Practice for Conducting Plant Corrosion Tests." In each unit, ten coupons, approximately 6 inches in diameter and 1/4-inch in thickness, were mounted on racks at various depths below the waterline and at the surface. The coupons were examined at 1-month, 3-months, 6-months, 1-year, 3-years, 5 ½-years, 7-years, and 8 $^{2}/_{3}$-years, for weight loss, and changes in dimension. In addition, samples were sectioned, mounted, and polished for microscopic examination. Based on the average results for the 10 coupons per evaluation, the corrosion rate decreased significantly with increased time exposure and stabilized to an average rate of 0.00116 inches/year after 8 $^{2}/_{3}$ years. This stabilized corrosion rate is attributed to the formation of a corrosion byproduct film on the surface of the coupons, thereby retarding further corrosion. The Corrosion Monitoring Program was discontinued after all the samples were evaluated and the long-term general corrosion rate had been established. In addition, all original coatings were removed between 1994 and 1996, and new coatings were applied to all accessible surfaces below the waterline.

  The UT measurements of thickness taken from 1982 to 1985 compared favorably with the corrosion rate determined from the coupon monitoring program. The higher corrosion rate of 0.00116 inches/year was used in the corrosion loss calculations prepared in the 1990s and is considered to remain conservative based on the trending obtained from the Corrosion Monitoring Program.

- Visual inspections of the torus components in the vapor zone indicate a film characterized as magnetite by its dark brownish-black color and tightly adherent nature. The Corrosion Monitoring Program did not include measurements of the liner above the waterline since it was considered to be represented by the results from below the waterline and because the containment atmosphere is inerted with nitrogen to limit the oxygen concentration to less than four-percent volume (in accordance with plant technical specifications).

ASME Code Section XI, Subsection IWE, requires visual inspection of examination category E-A, "Containment Surfaces." This examination includes structures that are part of the reinforcing structure, surface areas that are wetted or submerged, and weld attachments. The general visual examination is performed by an examiner with visual acuity sufficient to detect evidence of degradation that may affect either containment structural integrity or leak tightness. The visual examination of coated areas are inspected for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Suspect coated areas are accepted based on an engineering evaluation or corrected by repair or replacement activities. The visual examination of non-coated areas are examined for cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Like suspect coated areas, suspect non-coated areas are accepted based on an engineering evaluation or corrected by repair or replacement activities.

As stated above, the results of the torus inspections reveal a tightly adhering corrosion, scattered rust stains, and mechanical marks. Based on discussions with the staff during a teleconference on May 18, 2005, the applicant supplemented its response, by letter dated June 14, 2005, with the following to address the characterization of the tightly adhering corrosion and scattered rust stains and how these were determined to be bounded by the corrosion rate assumed in its analyses:

- The characterization of the corrosion as tightly adhering indicates no significant amount of loose or flaking rust present. Quality control inspection results indicate very little change in the appearance or quantity of corrosion deposits obtained through numerous inspections of torus components performed between 1994 and 2005.

- The rust stains are occurring on coated surfaces below bare surfaces with general corrosion, where a thin oxide layer is carried by moisture and runs down over the coated surface. The rust stain indicates that corrosion has occurred on adjacent surfaces above or near the stain.

- The qualitative visual examinations are not used to directly validate the quantitative values in the corrosion analysis but demonstrate that corrosion is occurring at a low rate consistent with the analysis.

The staff found that the aforementioned details support the assertion that the rate of corrosion of components within the vapor zone is occurring slowly and is bounded by the applicant's corrosion rate analysis, because consistent inspection data indicate no significant change in the appearance, quantity, or location of the corrosion.

The applicant determined the corrosion rate for the torus and ASME Code Section XI, inservice-inspection components through two separate methods. Actual UT measurements of the wall thickness below the water line yielded a corrosion rate of 0.00105 inches/year while results of a coupon corrosion test yielded a corrosion rate of 0.00116 inches/year. The coupon corrosion test was based on ASTM G4-68, which provides procedures for conducting immersion corrosion tests under operating conditions to evaluate the corrosion resistance of the material. The standard provides guidance such that some pitfalls associated with this testing are avoided. Specific to the standard are methods for mounting the apparatus, preparing the coupons, and completing examinations of the coupons. The staff found the application of the 0.00116 inches/year corrosion rate for the torus and ASME Code Section XI, inservice-inspection components appropriate because it is supported by actual UT measurements and an ASTM corrosion coupon test. In addition, although this corrosion rate was determined from data taken in the early 1980s through the early 1990s, the staff does not expect that the corrosion rate will vary significantly in the period of extended operation because of the combination of torus water chemistry controls, favorable inspection results from the torus recoating activities in the early 1990s, and the periodic IWE inspections.

Plant technical specifications required that the containment atmosphere be inerted with nitrogen gas, thereby exposing the torus and ASME Code Section XI, inservice-inspection components (in the vapor zone) to a low oxygen level environment. It is in this deaerated steam environment that the corrosion product magnetite would form, and the corrosion rate of magnetite-filmed steel is known to be extremely low. Based on the inspections performed, the identification of magnetite on the components, and the maintenance of a deaerated environment, the staff found that the application of the 0.00116 inches/year corrosion rate to the components in the vapor zone acceptable because this corrosion rate is based on actual measurements of the liner in an immersion environment that may be more corrosive. In addition, the controls on the torus vapor zone environment provide reasonable assurance that the assumed corrosion rate is bounding.

Based on the discussion above and a review of operating experience performed by the audit team documented in its Audit and Review Report, the staff found that the management of the torus and ASME Code Section XI, inservice-inspection components through the aforementioned inspections and evaluations are appropriate and sufficient to ensure that the corrosion rate of these components will not exceed the corrosion rate assumed in the TLAA.

<u>Non-ASME, Section XI, ISI Component Supports</u>. Section 54.21(c)(1)(iii) of 10 CFR requires the applicant to demonstrate that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The applicant proposed to manage the aging effects of the non-ASME Code Section XI, inservice-inspection component supports through the One-Time Inspection Program to determine the actual corrosion rate for these components. Based on the results of the measurements, follow-up actions will be taken to project the corrosion allowance analyses to the end of the period of extended operation or to establish aging management activities which may include further examination or replacement of components.

In RAI 4.7.4-2, dated March 17, 2005, the staff requested additional information from the applicant. The information requested is summarized as follows:

- Baseline inspections performed and the results of these inspections for each in-scope component from which the corrosion rate will be determined;

- Details in the One-Time Inspection Program to ensure that all the non-ASME Code Section XI, inservice-inspection components are in scope for this program and ultrasonically tested, and that the results are analyzed and evaluated for the period of extended operation; and

- Clarification of the components within the scope of non-ASME Code Section XI, inservice-inspection component supports and their environment(s).

In its letter dated March 31, 2005, the applicant responded to the staff's request as summarized below:

- There were no baseline inspections performed. The results from the One-Time Inspection Program will be subtracted from the original design thickness plus the mill tolerance to determine the corrosion rate. UT of coated locations may also be used to determine a representative corrosion rate. Visual observations of the torus indicate that the existing corrosion is passive and tightly adhering which would indicate that the previous corrosion rate is excessively conservative.

- The components within scope for the One-Time Inspection Program are those that could not be qualified for 60 years of operation. These components are the vent header lower support columns; torus platform upper column, structure, and grating; and miscellaneous supports. The miscellaneous supports are HPCI turbine exhaust line pipe supports, RCIC turbine exhaust line supports, RHR test line pipe supports, RHR containment cooling line (torus spray header) supports, and miscellaneous small bore pipe and conduit supports.

- The components subject to the One-Time Inspection Program and the environments for these components are as follows:

    - vent header lower support column in the vapor and immersion zones
    - torus platform grating in the vapor zone
    - torus platform structure in the vapor zone
    - torus platform upper column in the vapor zone
    - HPCI turbine exhaust line pipe supports in the immersion zone
    - RCIC turbine exhaust line pipe supports in the vapor and immersion zones
    - RHR test line pipe supports in the vapor and immersion zones
    - RHR containment cooling line (torus spray header) supports in the vapor zone
    - miscellaneous small bore pipe and conduit supports in the vapor zone

Based on discussions with the staff on May 18, 2005, the applicant supplemented its response, by letter dated June 14, 2005, with the following to address the accuracy of calculating the corrosion rate described above:

- The mill tolerance will generate a conservative corrosion rate because it maximizes the amount of material lost over the service life of the component.
- The mill tolerance is based on weight (in accordance with the American Institute of Steel Construction Manual), not thickness. The mill tolerance for typical structural members is ±2.5 percent.

In the absence of baseline thickness data, the staff found this method for calculating a corrosion rate conservative because it predicts a larger corrosion rate than would be expected given the environment and analysis for other components in similar environments.

As described in the GALL AMP XI.M32, "One-Time Inspection," One-Time Inspection Programs may be used to confirm that slowly progressing aging effects will not affect the component structure or intended function. The staff noted that the scope of the applicant's One-Time Inspection Program as described in a table in LRA Section B.2.15, "One-Time Inspection Program," includes the uncoated component supports and portions of the torus liner.

Based on discussions with the staff on May 18, 2005, the applicant supplemented its response, by letter dated June 14, 2005, with the following to information related to the One-Time Inspection Program for torus components:

- The one-time inspection is applicable to carbon steel in the vapor and immersion zone.

- A sampling process will be implemented to establish the corrosion rate with the following guidance for the sample population:

  - Sufficient number of locations from the vapor and immersion zones must be chosen.
  - The original corrosion rate was determined based on three UT readings from 16 locations on the liner, below the waterline, and throughout the torus.
  - Three UT readings are proposed to be taken from four locations in the immersion zone and three UT readings from eight locations in the vapor zone. Sample locations shall be taken from the components listed (within scope for non-ASME, Section XI, torus supports).

The staff found the use of the one-time inspection to obtain data to calculate a corrosion rate acceptable because:

- Numerous inspections to date have demonstrated that the corrosion of the components is slowly progressing,

- The scope of the one-time inspection includes the appropriate components, and

- The sampling process accounts for the different environments (i.e., vapor and immersion) as well as an appropriate number of measurements and locations for the components sampled.

Based on the discussions above, the staff found the non-ASME Code Section XI, components supports will be adequately managed based on the method for calculating the corrosion rate with the use of thickness measurements obtained from the One-Time Inspection Program.

4.7.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the torus component corrosion allowance in LRA Section A.1.2.8. On the basis of its review of the UFSAR supplement, the staff found that the summary description of the applicant's actions to address the torus component corrosion allowance is adequate.

4.7.4.4 Conclusion

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the uncoated torus liner and torus ASME Code Section XI inservice-inspection component supports of the torus component corrosion allowance TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the uncoated torus liner and torus ASME Code Section XI inservice-inspection component supports of the torus component corrosion allowance TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

On the basis of its review, as discussed above, the staff concluded that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the uncoated torus non-ASME Code Section XI inservice-inspection component supports of the torus component corrosion allowance TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concluded that the UFSAR supplement contains an appropriate summary description of the uncoated torus non-ASME Code Section XI inservice-inspection component supports of the torus component corrosion allowance TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

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SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. The applicant and the staff from the U.S. Nuclear Regulatory Commission (NRC or the staff) will meet with the subcommittee and the full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and the SER, the full committee will issue a report discussing the results of the review. An update to this SER will include the ACRS report. This update will also include the staff’s response to any issues and concerns identified in the ACRS report.

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SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) reviewed the license renewal application (LRA) for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2, in accordance with the NRC regulations and NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated July 2001. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

On the basis of its evaluation of the LRA, the staff determined that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 are documented in draft Supplement 25 to NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Brunswick Steam Electric Plant, Units 1 and 2, Final Report,” dated August 30, 2005.

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APPENDIX A

COMMITMENTS FOR LICENSE RENEWALS OF BSEP UNITS 1 AND 2

During the review of the Brunswick Steam Electric Plant (BSEP) Units 1 and 2, license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff), the applicant made commitments related to aging management programs (AMPs) to manage aging effects of structures and components (SCs) prior to the periods of extended operation. The following table lists these commitments, along with the implementation schedules and the sources of the commitment.

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Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
1	The elements of corrective action, confirmation process, and administrative controls in the BSEP QA Program will be applied to required aging management activities for both safety related and non-safety related structures and components subject to aging management review.	A.1.1	Prior to the period of extended operation	Quality Assurance (QA) LRA Section B.1.3
2	The BSEP FAC susceptibility analyses will be updated to include additional components potentially susceptible to FAC.	A.1.1.5	Prior to the period of extended operation	Flow-Accelerated Corrosion (FAC) Program LRA Section B.2.5
3	The Bolting Integrity Program will be enhanced to: (1) add a precautionary note to bolting guidelines to limit the sulfur content of compounds used on bolted connections, (2) include ASME, Section XI, activities identified in NUREG-1801, Program XI.M18, and (3) incorporate monitoring and trending criteria under Systems Monitoring for bolted connections outside of ASME, Section XI, boundaries.	A.1.1.6	Prior to the period of extended operation	Bolting Integrity Program LRA Section B.2.6, Commitment Items (2) and (3) were added in response to Audit Question (AQ) 3.2-4 in BSEP letter dated March 14, 2005

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
4	The Open-Cycle Cooling Water System Program will be enhanced to require that: (1) Program scope include portions of the Service Water (SW) System credited in the Aging Management Review, including non-safety related piping, (2) the Residual Heat Removal (RHR) Heat Exchangers will be subject to eddy current testing with results compared to previous testing to evaluate degradation and aging, (3) a representative sampling of SW Pump casings be inspected, (4) Program procedures be enhanced to include verification of cooling flow and heat transfer effectiveness of SW Pump Oil Cooling Coils, inspections associated with SW flow to the Diesel Generators (including inspection of expansion joints), and inspection and replacement criteria for RHR Seal Coolers, (5) piping inspections will include locations where throttling or changes in flow direction might result in erosion of copper-nickel piping, and (6) performance testing of the RHR and Emergency Diesel Generator Jacket Water heat exchangers will be performed to verify heat transfer capability.	A.1.1.7	Prior to the period of extended operation	Open-Cycle Cooling Water System Program LRA Section B.2.7, Commitment Item (6) was added in response to AQ B.2.7-1 in BSEP letter dated March 31, 2005.
5	Closed-Cycle Cooling Water System Program activities will be enhanced to assure that Preventive Maintenance activities include inspections of Diesel Generator (DG) combustion air intercoolers and heat exchangers	A.1.1.8	Prior to the period of extended operation	Closed-Cycle Cooling Water System Program LRA Section B.2.8

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
6	Administrative controls for the Program will be enhanced to: (1) include in the Program all cranes/platforms within the scope of License Renewal, (2) specify an annual inspection frequency for the Reactor Building Bridge Cranes and the Intake Structure Gantry Crane, and every fuel cycle for the Refuel Platforms, (3) allow use of maintenance crane inspections as input for the condition monitoring of License Renewal cranes, (4) require maintenance inspection reports to be forwarded to the responsible engineer, and (5) include inspection of structural component corrosion and monitoring crane rails for abnormal wear.	A.1.1.9	Prior to the period of extended operation	Inspection of Overhead Heavy Load and Light Load Handling LRA Section B.2.9
7	Program administrative controls will be enhanced to require: (1) obtaining non-intrusive baseline pipe thickness measurements at various locations, and (2) replacing the remainder of the plant's sprinkler heads prior to 50 years of sprinkler head service life. The results of the non-intrusive Fire Water System piping thickness measurements will be trended throughout the extended period of operation; the specific measurement intervals will be determined by engineering evaluation performed after each inspection to detect degradation prior to the loss of intended function.	A.1.1.11	Prior to the period of extended operation	Fire Water System Program LRA Section B.2.11, Commitment was revised in BSEP letter dated July 18, 2005 based on the NRC License Renewal Inspection of June 7 to 10, 2005.
8	The Aboveground Carbon Steel Tanks Program is a new aging management program that will be implemented.	A.1.1.12	Prior to the period of extended operation	Aboveground Carbon Steel Tanks Program LRA Section B.2.12

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
9	The Fuel Oil Chemistry Program administrative controls will be enhanced to: (1) add a requirement to trend data for water and particulates, (2) verify the condition of the in-scope fuel oil tanks by means of thickness measurements under the One-Time Inspection Program, and (3) perform an internal inspection of the Main Fuel Oil Storage Tank under the One-Time Inspection Program.	A.1.1.13	Prior to the period of extended operation	Fuel Oil Chemistry Program LRA Section B.2.13
10	The Reactor Vessel Surveillance Program will be enhanced to ensure that any additional requirements that result from the NRC review of Boiling Water Reactor Vessel Internals Program (BWRVIP)-116 are addressed.	A.1.1.14	Prior to the period of extended operation	Reactor Vessel Surveillance Program LRA Section B.2.14

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
11	The One-Time Inspection Program is a new aging management program that will be implemented and will include: (1) procedural controls to track, implement, complete, and report activities associated with one-time inspections, (2) inspection of the non-safety related core shroud head and separators and the surveillance capsule holder, (3) inspection of at least one of the four Emergency Diesel Engine Sumps, and at least one of the ten Service Water Pump Lubricating Oil Cooling Coils for corrosion products and evidence of moisture, and (4) application of inspection criteria consistent with NUREG-1801, Program XI.M32, including identification of specific sampling techniques, inspection locations, sample size, identification of inspection locations, examination technique, acceptance criteria, and evaluation of the need for follow-up examinations to address aging management program effectiveness for less than four-inch piping and fittings within ASME Code Class 1 boundaries. Verification of aging management program effectiveness for less than four-inch Class 1 piping components will be implemented by means of a sample of limiting components, scheduled late in the current operating term, at locations based on physical accessibility, exposure levels, NDE techniques, and locations identified in NRC Information Notice 97-46, as applicable, and applying an inspection of the inside surfaces of piping by destructive examination of replaced plant piping during modifications or NDE to ensure that cracking has not occurred.	A.1.1.15	Prior to the period of extended operation	One-Time Inspection Program LRA Section B.2.15, Commitment Item (2) was added in response to Request for Additional Information (RAI) B.2.28-8 in BSEP letter dated July 18, 2005. Item (3) was added in response to RAI 3.3-3 in BSEP letter dated August 11, 2005. Item (4) was added in response to AQs B.2.15-1 and B.2.15-2 in BSEP letter dated March 14, 2005.
12	The Selective Leaching of Materials Program is a new aging management program that will be implemented and will require a sample population of susceptible components to be selected for inspection.	A.1.1.16	Prior to the period of extended operation	Selective Leaching of Materials Program LRA Section B.2.16

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	Commitment	Updated Final Safety Analysis Report (UFSAR) Supplement Location	Implementation Schedule	Source
13	The Buried Piping and Tanks Inspection Program is a new aging management program that will be implemented and will include procedural requirements to: (1) ensure an appropriate as-found pipe coating and material condition inspection is performed whenever buried piping within the scope of the Buried Piping and Tanks Inspection Program is exposed, or, as a minimum, once every 10 years, (2) add precautions concerning excavation and use of backfill to the excavation procedure to include precautions for License Renewal piping, (3) add a requirement that coating inspection shall be performed by qualified personnel to assess its condition, and (4) add a requirement that a coating engineer or other qualified individual should assist in evaluation of any coating degradation noted during the inspection.	A.1.1.17	Prior to the period of extended operation	Buried Piping and Tanks Inspection Program LRA Section B.2.17, the 10-year period in Commitment Item (1) was added in response to AQ B.2-17-1 in BSEP letter dated March 14, 2005.
14	The ASME Section XI, Subsection IWF Program will be enhanced to include the torus vent system supports within the scope of the Program.	A.1.1.20	Prior to the period of extended operation	ASME Section XI, Subsection IWF Program LRA Section B.2.20
15	The administrative controls for the Masonry Wall Program will be enhanced to require inspecting all accessible surfaces of the walls for evidence of cracking.	A.1.1.22	Prior to the period of extended operation	Masonry Wall Program LRA Section B.2.22

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
16	The Structures Monitoring Program will be enhanced to: (1) identify License Renewal systems managed by the Program and inspection boundaries between structures and systems, (2) require notification of the responsible engineer regarding availability of exposed below-grade concrete for inspection and require that an inspection be performed, (3) identify specific License Renewal commodities and inspection attributes, (4) require responsible engineer review of groundwater monitoring results, (5) specify that an increase in sample size for component supports shall be implemented (rather than should be) commensurate with the degradation mechanisms found, (6) improve training of system engineers in condition monitoring of structures, (7) include inspections of submerged portions of the Service Water Intake Structure on a frequency not to exceed five years, (8) specify an annual groundwater monitoring inspection frequency for concrete structures, and (9) specify the inspection frequency for the Service Water Intake Structure and Intake Canal to not exceed five years.	A.1.1.23	Prior to the period of extended operation	Structures Monitoring Program LRA Section B.2.23, Commitment Items (7), (8), and (9) were added in response to AQ B.2.23-2 in BSEP letter dated March 14, 2005.

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
17	The Protective Coating Monitoring an Maintenance Program administrative controls will be enhanced to: (1) add a requirement for a walk-through, general inspection of containment areas during each refueling outage, including all accessible pressure-boundary coatings not inspected under the ASME Section XI, Subsection IWE Program, (2) add a requirement for a detailed, focused inspection of areas noted as deficient during the general inspection, (3) assure that the qualification requirements for persons evaluating coatings are consistent among the Service Level I coating specifications, inspection procedures, and application procedures, and meet the requirements of ANSI N 101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," and (4) document the results of inspections and compare the results to previous inspection results and to acceptance criteria.	A.1.1.24	Prior to the period of extended operation	Protective Coating Monitoring and Maintenance Program LRA Section B.2.24
18	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new aging management program that will be implemented.	A.1.1.25	Prior to the period of extended operation	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program LRA Section B.2.25

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
19	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program is a new aging management program that will be implemented and will include, for radiation monitoring instrumentation cables not included in the BSEP EQ Program, a review of calibration or surveillance results for indication of cable or connection degradation commencing before the end of the operating license term and at least once every 10 years thereafter. For cables in neutron flux instrumentation circuits testing frequency will be based on engineering evaluation not to exceed 10 years.	A.1.1.26	Prior to the period of extended operation	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program LRA Section B.2.26, Commitment was revised in response to AQ B.2.26-1 and AQ B.2.26-4 in BSEP letter dated March 14, 2005.
20	The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new aging management program that will be implemented and will include the provision that manholes containing medium-voltage cables in the scope of License Renewal will be inspected and accumulated water will be removed at least every two years by the Preventive Maintenance Program.	A.1.1.27	Prior to the period of extended operation	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program LRA Section B.2.27, Commitment was revised in response to AQ B.2.27-1 in BSEP letter dated March 14, 2005.

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
21	The Program will be enhanced to: (1) expand the Program scope to include an evaluation of each reactor coolant pressure boundary component included in NUREG/CR-6260, (2) provide preventive action requirements including requirement for trending and consideration of operational changes to reduce the number or severity of transients affecting a component, (3) include a requirement to reassess the locations that are monitored considering the RCPB locations that were added to the Program scope, (4) specify the selection criterion to be locations with a 60-year CUF value (including environmental effects where applicable) of 0.5 or greater, other than those identified in NUREG/CR-6260, (5) address corrective actions for components approaching limits, with options to include a revised fatigue analysis, repair or replacement of the component, or in-service inspection of the component (with prior NRC approval), and (6) address criteria for increasing sample size for monitoring if a limiting location is determined to be approaching the design limit.	A.1.1.28	Prior to the period of extended operation	Reactor Coolant Pressure Boundary (RCPB) Fatigue Monitoring Program LRA Section B.3.1, Commitment Items (1) and (4) were revised in response to AQ B.3.1-1 in BSEP letter dated March 14, 2005.

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
22	The Reactor Vessel and Internals Structural Integrity Program will be enhanced to: (1) incorporate augmented inspections of the top guide using enhanced visual examination or other acceptable inspection methods that will focus on the high fluence region, (2) establish inspection criteria for the VT-3 examination of the Core Shroud Repair Brackets, (3) the scope of the program described in the UFSAR Supplement will be revised to state that the program implements the following or latest BWRVIP guidelines: BWRVIP-03, BWRVIP-18, BWRVIP-25, BWRVIP-26, BWRVIP-27, BWRVIP-38, BWRVIP-41, BWRVIP-47, BWRVIP-48, BWRVIP-49, BWRVIP-74-A, BWRVIP-76, BWRVIP-94, and BWRVIP-139 (when reviewed and approved by the NRC) and (4) the scope of the program described in the UFSAR Supplement will be revised to state that: • the Reactor Vessel and Internals Structural Integrity Program in conjunction with the Water Chemistry Program will be used to manage flow blockage due to fouling of the Core Spray lines and spargers (spray nozzles), • the Reactor Vessel and Internals Structural Integrity Program will be used to manage the aging of the non-safety related steam dryers and feedwater spargers, • loss of preload due to stress relaxation of the Unit 2 spring-loaded core plate plugs will be managed by replacing the plugs. Any evaluation to extend the service life of the spring-loaded core plate plugs will be submitted to the NRC for review and approval, and • either an ultrasonic examination alone or with a visual examination will be performed for the	A.1.1.30	Prior to the period of extended operation	Reactor Vessel and Internals Structural Integrity Program LRA Section B.2.28, Commitment Items (1), (3), and (4) were revised in response to RAI B.2.28-15 in BSEP letter dated June14, 2005. Item (3) and bullets two and three of Item (4) were revised by RAI B.2.28-15 (Supplemental Response) in BSEP letter dated July 18, 2005. Bullet four of Item (4) was added in response to RAI B.2.28-6 in BSEP letter dated July 18, 2005.

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
23	A procedure will be developed to implement: (1) inspection of in-scope License Renewal components for identified aging effects, (2) guidelines for establishing inspection frequency requirements, (3) listing of inspection criteria in checklist form, (4) recording of extent of condition during system walkdowns, and (5) addressing of appropriate corrective action(s) for degradations discovered.	A.1.1.31	Prior to the period of extended operation	Systems Monitoring Program LRA Section B.2.29
24	Preventive maintenance activities will be incorporated into the PM Program, as needed, to accomplish aging management activities for components. Program activities include: (1) routine internal visual inspections for corrosion of the Demineralized Water Tank, (2) regular monitoring and removal of debris to manage accumulation of sludge, dirt/dust, rust, and other miscellaneous debris in the torus, (3) periodic inspection of high-voltage insulators for water beading on silicone coating and for age related degradation, (4) routine sampling and analysis to address corrosion concerns related to potential water intrusion into lubricating oil in the Service Water Pump Motor Cooler Coils and the Emergency Diesel Engines Lube Oil System, and (5) inspections of floor drains periodically exposed to service water and roof drains exposed to coastal atmospheric conditions to address aging concerns related to potential locally aggressive environments.	A.1.1.32	Prior to the period of extended operation	Preventive Maintenance (PM) Program LRA Section B.2.30, Commitment Item (1) was added in response to AQ B.2.2-6 in BSEP letter dated March 14, 2005. Item (2) was added in response to AQ B.2.24-1 in BSEP letter dated March 14, 2005. Item (3) was added in response to RAI 3.6.2.3-3 in BSEP letter dated June 14, 2005. Item (4) was added in response to RAI 3.3-3 in BSEP letter dated August 11, 2005. Item (5) was added in response to RAI 3.3.2-5-1 in BSEP letter dated August 11, 2005.

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
25	The Phase Bus Aging Management Program is a new aging management program that will be implemented and will include: (1) inspecting the interior condition of the bus enclosure for foreign debris, excessive dust build up, and evidence of water intrusion, (2) use of the Structures Monitoring Program to inspect the external surfaces of the phase bus housing, and (3) checking accessible and inaccessible Phase Bus bolted connections for loose connections by thermography or by measuring connection resistance using a low range ohmmeter on a 10-year frequency. Thermography will be performed while the bus is energized and loaded.	A.1.1.33	Prior to the period of extended operation	Phase Bus Aging Management Program LRA Section B.2.31, Commitment Items (1) and (2) were added in response to RAI 3.6.2.3-1 in BSEP letter dated June 14, 2005. Item (3) was added in response to RAI 3.6.2.3-1.b.3 in BSEP letter dated July 18, 2005.
26	The Fuel Pool Girder Tendon Inspection Program will be enhanced to: (1) specify inspection frequencies, numbers of tendons to be inspected, and requirements for expansion of sample size, (2) identify test requirements and acceptance criteria for tendon lift-off forces, measurement of tendon elongation, and determination of ultimate strength, (3) specify inspections for tendons, tendon anchor assemblies, surrounding concrete, and grease, (4) require prestress values to be trended and compared to projected values, and (5) identify acceptable corrective actions for tendons that fail to meet testing criteria.	A.1.1.34	Prior to the period of extended operation	Fuel Pool Girder Tendon Inspection Program LRA Section B.2.32
27	P-T limit curves for use during the periods of extended operation of BSEP Units 1 and 2 will be submitted for NRC review and approval in accordance with the 10 CFR 50.90 license amendment process at least one year prior to expiration of the 32 EFPY P-T limit curves that are currently approved in the BSEP Technical Specifications. Also, if an exemption request to permit the use of ASME Code Case N-640 is required as part of the submittal, an exemption request will be included as part of the license amendment request.	A.1.2.1.3	As noted in the commitment	Time Limited Aging Analysis (TLAA) - RPV Operating Pressure-Temperature (P-T) Limits LRA Section 4.2.4, Commitment was added in response to RAI 4.2.4-1 in BSEP letter dated May 4, 2005, and revised in response to RAI 4.2.4-1 (Supplemental Response) in BSEP letter dated July 18, 2005.

Brunswick Steam Electric Plant (BSEP) License Renewal Commitments, Revision 7				
Item No.	**Commitment**	**Updated Final Safety Analysis Report (UFSAR) Supplement Location**	**Implementation Schedule**	**Source**
28	Management of Core Plate Plug Spring Stress Relaxation will be performed by means of the Reactor Vessel and Internals Structural Integrity Program.	A.1.2.1.7 A.1.1.30	As noted in the commitment	TLAA – Core Plate Plug Spring Stress Relaxation LRA Section 4.2.8
29	A Fuel Pool Girder Tendon Inspection Program will be implemented to assure design basis anchor forces required for the tendons to perform their intended function will continue to be maintained.	A.1.2.6 A.1.1.34	Prior to the period of extended operation	TLAA – Fuel Pool Girder Tendon Loss of Prestress LRA Section 4.7.2
30	Measurements are planned, using the One-Time Inspection Program, to verify by volumetric measurements the actual rate of corrosion of the supports and platform steel in the torus.	A.1.2.8 A.1.1.15	Prior to the period of extended operation	TLAA – Torus Component Corrosion Allowance LRA Section 4.7.4
31	An evaluation of plant and industry operating experience will be submitted for NRC review at least one year prior to the period of extended operation. The purpose of the evaluation will be to assure that relevant aging effects caused by operation at power uprate conditions are adequately addressed by aging management programs.	None Refer to the ACRS letter report on license renewal of Dresden/Quad Cities, dated September 16, 2004.	One year prior to the period of extended operation	Potential Aging Effects/Mechanisms Resulting from Power Uprate Commitment added in BSEP letter dated May 11, 2005

BSEP Letter Date	Serial Number	Subject	ADAMS Accession Number
March 14, 2005	BSEP 05-0041	Response to Audit Questions - License Renewal NUREG-1801 Consistency Audit	ML050810493
March 31, 2005	BSEP 05-0044	Response to Request for Additional Information - License Renewal	ML050970259
May 4, 2005	BSEP 05-0050	Response to Request for Additional Information - License Renewal	ML051330020
May 11, 2005	BSEP 05-0055	Response to Request for Additional Information - License Renewal	ML051370298
June 14, 2005	BSEP 05-0071	Response to Request for Additional Information - License Renewal	ML051720468

BSEP Letter Date	Serial Number	Subject	ADAMS Accession Number
July 18, 2005	BSEP 05-0097	Clarification of Responses to Requests for Additional Information - License Renewal	ML052070762
August 11, 2005	BSEP 05-0112	Supplemental Responses to Requests for Additional Information - License Renewal	ML052310238

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APPENDIX B: CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Carolina Power & Light Company (CP&L). This appendix also contains other correspondence regarding the NRC staff's review of the Brunswick Steam Electric Plant, Units 1 and 2 (under Docket Nos. 50-325 and 50-324).

October 18, 2004	In a letter (signed by C. J. Gannon), CP&L submitted its application to renew the operating license of the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. In its submittal, CP&L provided an original signed hard copy of the application, and 81 additional electronic copies of the application on CDs. (ADAMS Accession Number: ML043060406)
October 18, 2004	In a letter (signed by E. T. O'Neil), CP&L submitted one set of boundary drawings to the NRC Document Control Desk, and an additional 3 sets to NRR (i.e., Mr. S. K. Mitra, the License Renewal Project Manager for BSEP). (ADAMS Accession Number: ML043060006)
November 10, 2004	In a letter (signed by P. T. Kuo), the NRC acknowledged receipt and availability of the License Renewal Application (LRA) for BSEP, Units 1 and 2. (ADAMS Accession Number: ML043170248)
December 6, 2004	In the *Federal Register*, a "Notice of Acceptance for Docketing of the Application and Notice of Opportunity for Hearing Regarding Renewal of Facility Operating License Nos. DPR-71 and DPR-62 for an Additional 20 Year Period" is published, concerning the BSEP LRA.
January 4, 2005	In a letter (signed by P. T. Kuo), the NRC provided a Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process for License Renewal for BSEP, Units 1 and 2. (ADAMS Accession Number: ML050050568)
January 12, 2005	In the *Federal Register* (Volume 70, Number 8, pages 2188-2189), a Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process in support of the review of the application for renewal of the BSEP operating licenses for an additional 20 years.
February 24, 2005	In a letter (signed by R. L. Emch, Jr.), the NRC staff issued RAIs regarding Severe Accident Mitigation Alternatives (SAMA) for the BSEP LRA. (ADAMS Accession Number: ML050550262)
March 14, 2005	In a letter (signed by C. J. Gannon), CP&L provided responses to audit questions resulting from the License Renewal NUREG-1801 Consistency (with GALL) Audit. (ADAMS Accession Number: ML050810493)

March 17, 2005	In a letter (signed by S. K. Mitra), the NRC staff issued RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML050760084)
March 20, 2005	In a report (signed by R. L. Emch, Jr.), the NRC provided a summary of the site audit to support review of the LRA for BSEP, Units 1 and 2. (ADAMS Accession Number: ML050880508)
March 31, 2005	In a letter (signed by C. J. Gannon), CP&L provided responses to RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML050970259)
April 1, 2005	In a summary of a telephone conference held on January 12, 2005 (signed by S. K. Mitra), the NRC described the discussion between NRC staff and CP&L staff concerning draft RAIs pertaining to the BSEP, Units 1 and 2, LRA. (ADAMS Accession Number ML050910203)
April 8, 2005	In a letter (signed by S. K. Mitra), the NRC staff issued RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML050980244)
April 21, 2005	In a letter (signed by C. J. Gannon), CP&L provided a response to an RAI concerning the NRC staff's analysis of SAMAs performed in support of the BSEP LRA. (ADAMS Accession Number: ML051170260)
April 21, 2005	In a letter (e-mailed by J. Kozyra), CP&L provided a response to R. L. Emch, Jr. – NRC, concerning an RAI on SAMA. (ADAMS Accession Number: ML051220545)
April 25, 2005	In a letter (signed by S. K. Mitra), the NRC staff issued RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML051150161)
April 29, 2005	In a summary of a telephone conference held on March 31, 2005 (signed by R. L. Emch, Jr.), the NRC described the discussion between NRC staff and contractors, and CP&L staff, concerning SAMA RAIs for BSEP, Units 1 and 2. (ADAMS Accession Number ML051190231)
May 4, 2005	In a letter (signed by C. J. Gannon), CP&L provided responses to RAIs associated with the review of the BSEP LRA. (ADAMS Accession Number: ML051330020)
May 4, 2005	In a letter (e-mailed by J. Kozyra), CP&L provided a response to R. L. Emch, Jr. – NRC, concerning an RAI on SAMA 8. (ADAMS Accession Number: ML51680176)

May 4, 2005	In a letter (e-mailed by J. Kozyra), CP&L provided a response to R. L. Emch, Jr. – NRC, which is an Addendum to the SAMA RAI 8 response. (ADAMS Accession Number: ML051680188)
May 11, 2005	In a letter (signed by C. J. Gannon), CP&L provided a responses to RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML051370298)
May 16, 2005	In a letter (e-mailed by J. Kozyra), CP&L transmitted to the NRC the content of a forthcoming letter which provided supplemental information regarding CP&L's response to the SAMA 8 RAI. (ADAMS Accession Number ML051680147)
May 16, 2005	In a summary of a telephone conference conducted on April 7, 2005 (signed by R. L. Emch, Jr.), the NRC described the discussion between NRC staff and CP&L staff concerning the SAMA RAIs for BSEP, Units 1 and 2. (ADAMS Accession Number ML051680147)
May 18, 2005	In a letter (signed by S. K. Mitra), the NRC staff issued RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML051380587)
May 24, 2005	In a letter (signed by R. L. Emch, Jr.), the NRC staff issued an Environmental Scoping Summary Report associated with the staff's review of the applications by CP&L for renewal of the operating licensees for BSEP Units 1 and 2. (ADAMS Accession Number: ML051440479)
June 1, 2005	In a letter (signed by C. J. Gannon), CP&L provided a further response to the BSEP LR SAMA 1 through 8. (ADAMS Accession Number: ML051640476 and ML051590211)
June 14, 2005	In a letter (signed by C. J. Gannon), CP&L provided responses to RAIs associated with the NRC's review of the BSEP LRA. (ADAMS Accession Number: ML051720468)
July 18, 2005	In a letter (signed by C. J. Gannon), CP&L provided clarification of responses to RAIs associated with the NRC's review of the BSEP LRP. (ADAMS Accession Number: ML052070762)
July 22, 2005	In a letter (signed by V. M. McCree), the NRC transmitted an Inspection Report. The report documents the results of the inspection which examined BSEP's aging management programs to support license renewal. (ADAMS Accession Number: ML052100315)
August 11, 2005	In a letter (signed by C. J. Gannon), CP&L provided clarification of responses to RAIs associated with the NRC's review of the BSEP LRP. (ADAMS Accession Number: ML052310238)

August 25, 2005	In a letter (signed by S. K. Mitra), the NRC revised the LRA review schedule to change the Public Meeting regarding the Draft Supplemental Environmental Impact Statement (DSEIS) from October 20, 2005 to October 18, 2005 (ADAMS Accession Number: ML052370329)
August 30, 2005	In a letter (signed by P. T. Kuo), the NRC provided a copy of the NRC's draft plant-specific supplement to the Generic Environmental Impact Statement for license renewal, for Brunswick Units 1 and 2. (ADAMS Accession Number ML052430138)
September 29, 2005	In a letter (signed by C. J. Gannon), CP&L provided an annual report of changes to the BSEP current licensing basis (CLB) that materially affects the contents of the BSEP License Renewal Application, including the Updated Final Safety Analysis Report Supplement. (ADAMS Accession Number ML043060406)
November 22, 2005	In a letter (signed by Edward T. O'Neil), CP&L provided comments on the NRC's Draft NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 25, Regarding Brunswick Steam Electric Plant, Units 1 and 2." (ADAMS Accession Number ML)
December 6, 2005	In a letter (signed by James Scarola), CP&L provided a Revised License Renewal Commitment List for Brunswick Steam Electric Plant, Unit Nos. 1 and 2. (ADAMS Accession Number ML)

APPENDIX C: PRINCIPAL CONTRIBUTORS

NAME	RESPONSIBILITY
F. Akstulewicz	Management Oversight
H. Ashar	Civil Engineering
W. Bateman	Management Oversight
T Cheng	Civil Engineering
P. Chan	Mechanical Engineering
T. Chan	Management Oversight
R. Dennig	Management Oversight
R. Dipart	Fire Protection
T. Ford	Reactor Systems
B. FU	Pipeing Engineer
G. Galletti	Quality Assurance
F. Gillespie	Management Oversight
R. Goel	Containment Systems
J.Golla	Plant System
J. Hannon	Management Oversight
M. Hartzman	Mechanical Engineering
M. Heath	Project Manager
E. Imbro	Management Oversight
N. Igbal	Fire Protection
R. Jenkins	Management Oversight
C . Julian	Region II Inspections
K. Kavanagh	Quality Assurance
P. Kuo	Management Oversight
A. Lee	Component Performance
S. Lee	Management Oversight
C. Li	Plant Systems
Y. Li	Mechanical Engineering
C. Lauron	Component Performance
L. Lund	Management Oversight
J. Lyons	Management Oversight
K. Manoly	Management Oversight
T. Martin	Management Oversight
D. Matthews	Management Oversight
M. Mayfield	Management Oversight
R. McNally	Mechanical Engineering
J. Medoff	Materials Engineering
M. Mitchel	Management Oversight
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APPENDIX D: REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for Brunswick Steam Electric Plant, Units 1 and 2, Docket Numbers 50-325 and 50-324, respectively.

(18) NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” April 2001

(19) NEI 95-10, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule, Revision 3,” August 2001

(20) NUREG-1801, “Generic Aging Lessons Learned Report (GALL),” April 2001

(21) Letter From NRC to Carolina Power and Light Company, “Request For Additional Information (RAI) Regarding The License Renewal Application For The Brunswick Steam Electric Plant, Units 1 and 2"

(22) BNP-LR-606, “License Renewal Aging Management Program Description of the ASME, Section XI, Subsections IWB, IWC, and IWD, Inservice Inspection (ISI) Program,” Rev. 1

(23) BNP-LR-011, “Operating Experience (OE) Review of Materials and Programs For License Renewal,” Rev.0

(24) NRC Letter to Mr. C.J. Gannon from Victor M. McCree "Brunswick Steam Electric Plant-NRC Integrated Inspection Report Nos. 05000325/2004002 and 05000324/2004002; Preliminary White Finding,” April 19, 2004

(25) BNP-LR-600, “License Renewal Aging Management Program Description of the Water Chemistry Program,” Rev. 1

(26) BNP-LR-306, “LR AMR Reactor Vessel and Internals System,” Rev. 2

(27) NUREG-1544, “Status Report: Intergranular SCC of BWR Core Shroud and Other Internal Components,” March 1996

(28) NRC Regulatory Guide 1.65, “Materials and Inspections for Reactor Vessel Closure Studs,” October 1973

(29) NEDC-31735P, “BWR Operator's Manual for Materials and Processes,” (pg. 2.01-55), September 1990

(30) BNP-LR-654, “License Renewal Aging Management Program Description of the BWR Stress Corrosion Cracking Program,” Rev. 1

(31) 0ENP-16.2, “Administrative Control of ASME Section XI Non-destructive Examination Program,” Rev. 16

(32) CPL-53Q-301, “Risk Informed ISI Code Case N-578: Application to BSEP Units 1 and 2: Degradation Mechanisms Evaluation of Brunswick Units 1 and 2,” Rev. 2