Based on its review, the staff finds the applicant's response to RAI 2.3B.3.11-1 acceptable. The staff's concern described in RAI 2.3B.3.11-1 is resolved.

In RAI 2.3B.3.11-2, dated October 24, 2007, the staff stated that Section 3.1.8 of the fire protection SER for IP3, dated March 6, 1979, discusses dry-pipe, pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas. LRA Section 2.3.3.11 does not indicate that the dry-pipe pre-action sprinkler systems are within the scope of license renewal and subject to an AMR. The staff requested that the applicant verify whether the dry-pipe pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If they are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant stated that the dry-pipe, pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas are within the scope of license renewal and subject to an AMR. License renewal drawing LRA-9321-40913-001-0 shows the electrical tunnel dry pipe pre-action sprinkler systems 8, 8A, 9, and 9A at coordinates G6. The electrical tunnel sprinkler systems cover areas in the electrical penetration area and cable trays in the motor control center areas, in addition to the cable trays in the electrical tunnels. The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within scope and subject to an AMR.

Based on its review, the staff finds the response to RAI 2.3B.3.11-2 acceptable because the applicant identified the dry-pipe, pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas as within the scope of license renewal and subject to an AMR. Therefore, the staff concludes that the applicant correctly identified these dry-pipe, pre-action sprinkler systems and the associated components as within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.3.11-2 is resolved.

In RAI 2.3B.3.11-3, dated October 24, 2007, the staff stated that Section 5.9.1 of the March 6, 1979, fire protection SER for IP3 discusses automatic deluge foam suppression systems for various areas in the turbine building. LRA Section 2.3.3.11 does not indicate that the foam suppression systems are within the scope of the license renewal and subject to an AMR. The staff requested that the applicant verify whether the foam suppression systems for various areas in the turbine building are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the systems are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant stated that the fluid-containing portions of the foam suppression systems for various areas in the turbine building are included with miscellaneous systems, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR. LRA Table 3.3.2-19-20-IP3 summarizes the AMR results for the fluid-containing portions of the systems. Based on the discussion in the March 6, 1979, fire protection SER for IP3, the foam suppression systems for various areas in the turbine building meet the scoping requirements of

10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The applicant further identified the system components that are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The applicant indicated that LRA Table 3.3.2-11-IP3 summarizes the AMR results.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.11-3 acceptable because fluid-containing portions of the foam systems for various areas in the turbine building were identified as being within the scope of license renewal and subject to an AMR. The AMR results are summarized in LRA Table 3.3.2-20-IP3.

In RAI 2.3B.3.11-4, dated October 24, 2007, the staff stated that Section 5.11.1 of the March 6, 1979, fire protection SER for IP3 discusses wet pipe automatic sprinklers in the diesel generator building sump area beneath each diesel engine and on the diesel day tank. On license renewal drawing LRA-9321-40913-0, at coordinate E3, the wet pipe automatic sprinkler system does not appear to be within the scope of the license renewal and subject to an AMR (i.e., the box surrounding the sprinklers in question is not highlighted). The staff requested that the applicant verify whether the wet pipe sprinkler system designed to protect the diesel generator building sump area and diesel day tank is within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the system is excluded from the scope of license renewal and is not subject to an AMR, the staff asked the applicant to justify its exclusion.

In its response, dated November 16, 2007, the applicant stated that the IP3 wet pipe automatic sprinklers in the diesel generator building sump area beneath each diesel engine and on the diesel day tanks are in scope and subject to an AMR, as shown on license renewal drawing LRA-9321-40913-001-0, coordinate E3. The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within the scope of license renewal and subject to an AMR, along with the highlighted components on the drawing.

Based on its review, the staff finds the response to RAI 2.3B.3.11-4 acceptable because the applicant identified wet pipe automatic sprinklers in the diesel generator building sump area beneath each diesel engine and on the diesel day tank as within the scope of license renewal and subject to an AMR. Further, the applicant clarified that the absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within the scope of license renewal and subject to an AMR, along with the highlighted components on license renewal drawing LRA-9321-40913-001-0. Therefore, the staff concludes that the applicant correctly identified the wet pipe automatic sprinklers in question as within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.3.11-4 is resolved.

In RAI 2.3B.3.11-5, dated October 24, 2007, the staff stated that Section 5.13.1 of the March 6, 1979, fire protection SER for IP3 discusses the charcoal filter manual water spray system. LRA Section 2.3.3.11 does not indicate that the manual water spray system and its associated components are within the scope of the license renewal and subject to an AMR. The staff requested that the applicant verify whether the charcoal filter manual water spray system and its associated components are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the system is excluded from the scope of license renewal and is not subject to an AMR, the staff asked the applicant to justify its exclusion.

In its response, dated November 16, 2007, the applicant stated that the IP3 charcoal filter manual water spray system is in scope, as shown on license renewal drawing LRA-9321-40913-001-0 at coordinates H8. The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is in scope and subject to an AMR, along with the highlighted components on the drawing. License renewal drawing LRA-9321-40913-001-0 continues to an equipment arrangement drawing which is not available as a license renewal drawing.

Based on its review, the staff finds the response to RAI 2.3B.3.11-5 acceptable because the applicant identified the charcoal filter manual water spray system in question as within the scope of license renewal and subject to an AMR. Further, the applicant clarified that the absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within the scope of license renewal and subject to an AMR, along with the highlighted components on license renewal drawing LRA-9321-40913-001-0.

In RAI 2.3B.3.11-6, dated October 24, 2007, the staff stated that Section 5.15.1 of the March 6, 1979, fire protection SER for IP3 discusses automatic water spray systems for oil-filled transformers located adjacent to the control building. LRA Section 2.3.3.11 does not indicate that the automatic water spray systems and their associated components are within the scope of license renewal and subject to an AMR. The staff requested that the applicant verify whether the automatic water spray systems for oil-filled transformers are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the systems are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant stated that it initially determined that the automatic water spray systems and their associated components for the oil-filled transformers located adjacent to the control building did not have a license renewal intended function. The applicant believed that they were only required to protect the transformers, satisfying requirements of the plant insurance carrier. However, the spray systems provide for defense in depth, in addition to the installed 3-hour-rated fire barriers between the control building and the transformer yard, and are considered in scope and subject to an AMR. LRA Table 2.3.3-11-IP3 includes the applicable component types subject to an AMR, and LRA Table 3.3.2-11-IP3 provides the AMR results.

Based on its review, the staff finds the response to RAI 2.3B.3.11-6 acceptable because the applicant concluded that the automatic spray system for the oil-filled transformer performs a defense-in-depth function and, therefore, is within the scope of license renewal and subject to an AMR. The staff confirmed that LRA Table 3.3.2-11-IP3 provides the AMR results. Therefore, the staff finds that the applicant correctly identified the automatic water spray systems and their associated components for the oil-filled transformers as within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.3.11-6 is resolved.

2.3B.3.11.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fire protection - water system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.12 IP3 Fire Protection—Carbon Dioxide, Halon, and RCP Oil Collection Systems

2.3B.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 describes the fire protection—CO_2, Halon, and RCP oil collection system, which is listed under the following system codes:

- CO_2 system: system code CO2
- Halon: system code HAL
- RCP oil collection components: system code RCS

The CO_2 system provides fire protection and supplies CO_2 gas to purge the main generator. The CO_2 fire protection system has two 10-ton-capacity, low-pressure tanks, a distribution header, piping, and valves. An automatic total-flooding CO_2 fire suppression system protects the 480-V switchgear room, cable spreading room, diesel generator rooms, and the turbine generator exciter enclosure. A local application CO_2 fire suppression system protects the turbine building, including the main boiler FW pumps, turbine governor, MS and reheat valves, and generator bearings. Before maintenance work on the main generator, the hydrogen gas must be evacuated from the system. Inert CO_2 gas from a CO_2 gas-vaporizing system purges the generator. The IP2 CO_2 gas-vaporizing system also may operate through a supply line from the IP1 intake structure area.

The Halon 1301 system suppresses fires in the administration/service building technical support center/computer room, in the Appendix R diesel enclosure, and in the meteorological building. The Halon system does not protect any safety-related plant equipment. Protection of the Appendix R diesel enclosure from fire is not a required function under Appendix R. For IP3, the Halon 1301 system has no intended functions under 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3).

The RCP oil collection system is designed, engineered, and installed so an RCP lube oil system failure will not lead to fire during normal or DBA conditions or impact any safety-related system capability during a safe-shutdown earthquake. The collection system can collect lube oil from all pressurized and unpressurized potential leakage sites in the RCP lube oil systems and drain it to a vented closed tank that can hold the required lube oil system inventory. A flame arrester in each tank vent prevents fire flashback. The collection system consists of leakproof enclosures or pans under oil-bearing components to contain leaks.

The fire protection—CO_2 and RCP oil collection systems have no intended functions under 10 CFR 54.4(a)(1).

The scoping and screening methodology identified the following RCP oil collection system intended function, in accordance with 10 CFR 54.4(a)(2):

- Maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

The scoping and screening methodology also identified the following CO_2 and RCP oil collection systems intended functions, in accordance with 10 CFR 54.4(a)(3):

- Provide automatic and manual CO_2 flooding for areas of the plant that (1) contain safety-related equipment or (2) pose significant hazards to plant areas containing safety-related equipment (10 CFR 50.48) or both.

- Provide each RCP with an oil collection system that is designed to contain and direct the oil to remote storage containers in the event of an oil leak.

LRA Table 2.3.3-12-IP3 identifies fire protection—CO_2 and RCP oil collection systems component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11, UFSAR Sections 9.6.2.3 and 9.6.2.4, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

The staff also reviewed the following IP3 fire protection CLB documents listed in the IP3 Operating License Condition 2.H: NRC fire protection SERs for IP3 dated September 21, 1973; March 6, 1979; May 2, 1980; November 18, 1982; December 30, 1982; February 2, 1984; April 16, 1984; January 7, 1987; September 9, 1988; October 21, 1991; April 20, 1994; and January 5, 1995.

The staff also reviewed IP3 commitments associated with 10 CFR 50.48 (i.e., an approved fire protection program), using its commitment responses to BTP APCSB 9.5-1 and BTP APCSB 9.5-1, Appendix A.

During its review of LRA Section 2.3.3.12, the staff 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 2.3B.3.12-1, dated October 24, 2007, the staff asked the applicant to explain why license renewal drawing LRA-9321-24403-0 indicated that the following fire protection system components were not subject to an AMR (i.e., they are not highlighted in brown):

- Appendix R diesel generator Halon 1301 system
- technical support center/plant computer Halon system
- IP3 record room vault Halon 1301 system

The staff requested that the applicant verify whether the above components are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If these components are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant addressed each system individually. For the Appendix R diesel generator Halon 1301 system, the applicant stated that the Appendix R diesel generator is located in a standalone structure separated from other plant structures and equipment. The applicant further explained that the technical support center/plant computer and the record room vault are located in an administration building attached to the turbine building. The applicant added that a sprinkler system had replaced the IP3 record room vault Halon 1301 system.

The applicant stated that the areas referenced in the RAI response do not contain systems or components required for safe shutdown of the plant, do not provide an exposure hazard to any building or area required for safe shutdown, and are not located in safety-related areas. The applicable IP3 fire protection SER, dated March 6, 1979, credits no fire suppression systems for these areas. The Halon systems are not required for compliance with 10 CFR 50.48. The fire protection SER does not stipulate the addition of suppression systems for the Appendix R diesel generator, technical support center/plant computer, or the IP3 record room vault.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.12-1 acceptable. The applicant does not credit the Halon 1301 systems for the Appendix R diesel generator room, technical support center/plant computer room, and record room vault toward meeting the requirements of Appendix R to 10 CFR Part 50 for achieving safe shutdown in the event of a fire. Although the IP3 March 6, 1979, fire protection SER addresses the Halon 1301 systems for the Appendix R diesel generator room, technical support center/plant computer room, and record room vault, NRC fire protection regulations do not require these systems. The Appendix R diesel generator room, technical support center/plant computer room, and record room vault are not safety related and cannot affect safety-related equipment by spatial interaction. Furthermore, they are not required for safe shutdown. Therefore, they have no intended function under 10 CFR 54.4(a)(2). In addition, the staff reviewed commitments made by the applicant to satisfy BTP APCSB 9.5-1, Appendix A, which discusses Halon 1301 systems and found no intended function associated with 10 CFR 54.4(a)(2). Therefore, the staff finds that the applicant correctly excluded the Halon 1301 systems for the Appendix R diesel generator room, technical support center/plant computer room, and record room vault from the scope of license renewal and an AMR. The staff's concern described in RAI 2.3B.3.12-1 is resolved.

2.3B.3.12.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fire protection CO_2, Halon, and RCP oil collection system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.13 IP3 Fuel Oil Subsystems

2.3B.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the IP3 fuel oil subsystems, which include the IP3 EDGs, the IP3 fire protection diesel engines, and the IP3 Appendix R diesel generator.

Each diesel fuel oil storage and transfer system supplying fuel to the EDGs has its own fuel oil day tank and an underground storage tank. The day tanks are within the diesel generator buildings. An engine-driven fuel oil pump supplies the fuel from the day tank to the engine. The day tank fills automatically during engine operation from its dedicated underground storage tank, which is adjacent to the diesel generator building. Each underground storage tank has a motor-driven transfer pump to transfer fuel to the day tank.

Independent diesel fuel oil storage and transfer systems supply fuel to the IP2 and IP3 fire protection diesel engines. The IP3 fuel oil storage tank and components are located in the IP3 fire protection pump house.

An independent diesel fuel oil storage and transfer system supplies fuel to the IP3 Appendix R diesel generator, which has its own fuel oil day tank and underground storage tank. The day tank supplies fuel directly to the engine. A transfer pump fills the fuel oil day tank automatically from its storage tank during engine operation.

The fuel oil subsystems contain safety-related components relied on to remain functional during and following DBEs. They also contain nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the fuel oil subsystems perform functions that support fire protection and SBO.

LRA Table 2.3.3-13-IP3 identifies fuel oil subsystem component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13; UFSAR Sections 1.3.1, 8.2, and 16.1.3; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.13, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.13-1, dated February 13, 2008.

2.3B.3.13.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the fuel oil system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

2.3B.3.14 IP3 Emergency Diesel Generator System

2.3B.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the EDG system, which supplies emergency shutdown power upon loss of all other alternating current auxiliary power. The system consists of three EDG sets, each with a diesel engine coupled to a 480-V generator. Each emergency diesel is started automatically by two redundant air motors and has an air storage tank and compressor system, its own starting air subsystem, fuel oil subsystem, intake air subsystem, exhaust subsystem, lube oil subsystem, and jacket water cooling subsystem. The EDG system also has ventilation equipment for the diesel generator building.

The EDG system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. In addition, the EDG system performs functions that support fire protection.

The HVAC component parts of this system code are reviewed with HVAC systems (LRA Section 2.3.3.8). Fuel oil subsystem components are evaluated with fuel oil (LRA Section 2.3.3.13). Nonsafety-related components not evaluated with other systems and whose failure could prevent satisfactory accomplishment of safety functions are evaluated with miscellaneous systems (LRA Section 2.3.3.19). Remaining components are evaluated in LRA Section 2.3.3.14.

LRA Tables 2.3.3-14-IP3, 2.3.3-19-16-IP3, and 2.3.3-19-17-IP3 identify EDG system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14, UFSAR Sections 8.2 and 16.1.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.14, the staff 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 2.3B.3.14-1, dated December 7, 2007, the staff noted that a license renewal drawing for the IP3 jacket water to EDGs identified that the jacket water pumps for diesel engine Nos. 31, 32, and 33 are not subject to an AMR, in accordance with 10 CFR 54.21(a), because they are not long-lived components. The staff noted that SRP-LR, Table 2.3-2, provides examples of passive, long-lived components, such as diesel engine jacket water skid-mounted equipment. To complete its review, the staff requested that the applicant confirm that the jacket water pumps are short-lived components and describe its method for periodic replacement of these components.

In its response, dated January 4, 2008, the applicant stated that IP3 EDG maintenance procedures specify that the jacket water pumps in question are scheduled for replacement every 16 years, in accordance with station maintenance procedures, and, therefore, they are not subject to an AMR.

Based on its review, the staff finds the response to RAI 2.3B.3.14-1 acceptable because the applicant adequately explained that the practice of replacing the jacket water pumps meets the intent of 10 CFR 54.21(a)(1)(ii) for short-lived components and that the maintenance procedures control the pumps' periodic replacement. Therefore, the staff agrees that the jacket water pumps are not subject to an AMR. The staff's concern described in RAI 2.3B.3.14-1 is resolved.

In RAI 2.3A.3.14-2, dated December 7, 2007, the staff noted that license renewal drawings for the EDG jacket water cooling systems and EDG fuel oil systems for IP2 and IP3 label multiple "flexible conn [connections]" as not long-lived components. By letter dated January 4, 2008, the applicant responded to the staff's RAI. SER Section 2.3A.3.14 documents the RAI, the applicant's response, and the staff's evaluation.

The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.14-2, dated February 13, 2008.

2.3B.3.14.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the EDG system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.15 IP3 Security Generator System

2.3B.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 describes the security propane generator system, which supplies power for the security lighting system and other security functions. The applicant credits a portion of this security lighting under Appendix R, Section III.J (emergency lighting), to illuminate ingress and egress to the Appendix R diesel generator, main and backup SW pumps, CST, and RWST.

The security propane generator system performs functions that support fire protection.

LRA Table 2.3.3-15-IP3 identifies security propane generator system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

2.3B.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 and UFSAR Section 9.6.2.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.15.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the security propane generator system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.16 IP3 Appendix R Diesel Generator System

2.3B.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 describes the Appendix R diesel generator system, which supplies power to selected equipment and power supplies relied on in Appendix R and SBO events. The Appendix R diesel generator complies with SBO requirements and can supply sufficient power for safe-shutdown loads through the 6.9-kV distribution and the emergency 480-V buses and motor control centers or the turbine building switchgear and motor control centers. Located in a separate structure in the yard area, the Appendix R diesel generator installation is a self-contained package that operates upon a complete loss of power and includes a starting air compressor, batteries, battery charger, jacket water heater, lube oil heater, fuel oil pump and lube oil pumps, and necessary filters and strainers.

The Appendix R diesel generator system performs functions that support fire protection and SBO.

Fuel oil subsystem components are reviewed with fuel oil (LRA Section 2.3.3.13). Ventilation for the Appendix R diesel generator system is reviewed with HVAC systems (LRA Section 2.3.3.8). Remaining components are evaluated in LRA Section 2.3.3.16.

LRA Table 2.3.3-16-IP3 identifies Appendix R diesel generator system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16, UFSAR Sections 8.1.1 and 8.2.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.16.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the Appendix R diesel generator system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.17 IP3 City Water System

2.3B.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 describes the city water system, which supplies water to various components throughout the plant. The city water supply was installed originally for IP1, but now has functions for all three units. The IP2 city water description includes the city water tank and many of the shared site components. This system includes only the IP3 components. City water is used for a variety of purposes throughout IP3, such as supplying water to fire protection systems, to equipment for makeup or cooling, and to sanitary and potable facilities (e.g., emergency showers, eye wash stations, hose connections, sinks, water coolers, water heaters, and lavatories). The system also supplies a backup, but not a safety-grade, source of water to the AFW pumps and can supply makeup to the spent fuel pit.

The city water system contains nonsafety-related components whose failure could potentially prevent the satisfactory accomplishment of a safety-related function. In addition, the city water makeup performs functions that support fire protection.

Components of the city water system that provide water to the AFW system are reviewed with the AFW systems (LRA Section 2.3.4.3).

LRA Tables 2.3.3-17-IP3 and 2.3.3-19-13 identify city water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, UFSAR Sections 6.1.1 and 10.3.1, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.17, the staff 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 2.3B.3.17-1, dated December 7, 2007, the staff noted that the LRA states that the IP3 city water system has the intended function under 10 CFR 54.4(a)(3) of providing water to the fire protection tanks. The staff further noted that the applicant did not highlight on a license renewal drawing for the city water system a portion of the city water system piping upstream of the eight isolation valves to fire water storage tanks 1 and 2 to indicate that it is within the scope of license renewal. This piping connects to the 16-inch water main from the Village of Buchanan and provides makeup water for the fire water supply function. The staff asked the applicant to explain why it considered all of the city water system piping from the 16-inch water main for the

Village of Buchanan to the fire water storage tanks to be outside the scope of license renewal under 10 CFR 54.4(a)(3) and not subject to an AMR.

In its response, dated January 4, 2008, the applicant stated that the 16-inch water main from the Village of Buchanan is a source of makeup water for the city water system. The applicant explained that city water is the normal source of makeup water to the two fire water storage tanks; however, the city water source is not required to support any fire scenarios or Appendix R events, since each of the storage tanks has a sufficient reserve for fire fighting, without makeup, available to handle all fire scenarios. Therefore, although the city water system can provide a water supply to the fire water tanks, it is not a license renewal intended function, since makeup is not required for compliance with 10 CFR 50.48 fire scenarios or Appendix R events. As a result, the applicant changed LRA Section 2.3.3.17, for IP3, to delete the intended function bullet item, "provide water supply to the fire protection tanks (10 CFR 50.48)," as a 10 CFR 54.4(a)(3) function.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.17-1 acceptable because it adequately explained that, although city water is the normal source of makeup water to the two fire water storage tanks, the source is not required to support any fire scenarios or Appendix R events. Each of the storage tanks has a sufficient reserve for firefighting that can handle all fire scenarios without the need for continued makeup. Since makeup is not required for 10 CFR 50.48 fire scenarios or Appendix R events, the applicant has changed LRA Section 2.3.3.17, for IP3, to delete the intended function bullet item, "provide water supply to the fire protection tanks (10 CFR 50.48)," as a 10 CFR 54.4(a)(3) function. The staff's concern described in RAI 2.3B.3.17-1 is resolved.

In RAI 2.3B.3.17-2, dated December 7, 2007, the staff noted that the LRA states that the IP3 city water system has no intended functions, in accordance with 10 CFR 54.4(a)(1). However, the staff noted that, on a license renewal drawing for the city water system under "General Notes," the applicant stated under the heading "Class I Piping," "(1) above ground city water make-up to closed cooling water system—expansion tank in control room and EDG jacket water expansion tank," and "(2) city water from Unit 1 tie into AFW pumps suction." The staff also noted that under the heading "Class III Piping," the LRA states, "(1) above ground city water make-up to closed cooling water system—head tank in turbine building," and "(2) above ground city water supply to nuclear services."

In addition, the staff found that a license renewal drawing for the condensate and boiler feed pump suction system shows a small portion of the city water system piping. This portion of city water system piping is highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR. The drawing identifies this portion of city water system piping as Class I. By definition, all Class I and Class III piping should have intended functions under 10 CFR 54.4(a)(1). The staff requested that the applicant address the following:

(a) Explain why the Class I and Class III city water system piping on the two drawings do not have an intended function, in accordance with 10 CFR 54.4(a)(1).

(b) Explain why the city water piping up to the closed cooling water system expansion tank, EDG jacket water expansion tank, closed cooling water system head tank, and nuclear services on the one city water system license renewal drawing is not highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR.

(c) Explain why the city water system piping that continues from one city water license renewal drawing onto another drawing for supplying the 40-gallon EDG jacket water expansion tanks is also not highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR.

In its response, dated January 4, 2008, the applicant stated the following:

(a) Class I and Class III refer to seismic classification; not to ASME safety class, and that Class I components include safety-related equipment. The applicant further stated that Class I SSCs also include components that do not perform a safety function. The applicant explained Class III is the designation for SSCs which are not directly related to reactor operation and containment, and which do not have to maintain structural integrity during or following an SSE. Further, when defining the city water system components required to support a 10 CFR 54.4(a)(1) system intended functions for license renewal, the seismic classification boundaries were not used, since they do not accurately reflect the portions of the system required to meet system intended functions. Finally, the applicant explained that all components needed to accomplish system intended functions were included within scope regardless of the class breaks on the drawings.

(b) The license renewal drawings only highlight portions of systems within scope and subject to an aging management review for 10 CFR 54.4(a)(1) or (a)(3). The city water piping up to the closed cooling water system expansion tank, EDG jacket water expansion tank, closed cooling water system head tank, and nuclear services on the city water license renewal drawing is not required to meet any system intended functions described in 10 CFR 54.4(a)(1) or (a)(3); therefore, the piping is not highlighted. However, this piping and valves are within scope for 10 CFR 54.4(a)(2) due to the potential for spatial interaction and are included in LRA tables for components subject to an AMR.

(c) The LRA drawings only reflect portions of systems in scope and subject to aging management review for 10 CFR 54.4(a)(1) or (a)(3). The city water piping up to the diesel generator jacket water expansion tank on drawings LRA-9321-20343-001 and 9321-H-20283 is not required to meet any system intended functions described in 10 CFR 54.4(a)(1) or (a)(3) and therefore is not highlighted. However, this piping and valves are in scope for 10 CFR 54.4(a)(2) due to the potential for spatial interaction. They are included in LRA Tables 2.3.3-19-13-1P3 and 3.3.2-19-13-1P3.

City water is the source of makeup water to the 40-gallon diesel generator jacket water expansion tanks. Makeup water is not required for the EDGs to perform their intended function.

Based on its review, the staff finds the response to RAI 2.3B.3.17-2(a) acceptable because the applicant adequately explained that Class I and Class III on the license renewal drawing refer to seismic classification, rather than ASME safety class. Class I SSCs at IP2 and IP3 include components that do not perform a safety function. At IP2 and IP3, Class III is the designation for SSCs that are not directly related to reactor operation and containment and that do not have to maintain structural integrity during or following a safe-shutdown earthquake. The applicant did not use the seismic classification boundaries when defining the city water system components that are required to comply with 10 CFR 54.4(a)(1) system intended functions for license renewal, since they do not accurately reflect the portions of the system required to meet system intended functions. The applicant included all components needed to accomplish system intended functions within the scope of license renewal, regardless of the seismic class breaks on the drawings. The staff's concern described in RAI 2.3B.3.17-2(a) is resolved.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.17-2(b) acceptable because it adequately explained that the license renewal drawings reflect only the portions of systems within scope and subject to an AMR, in accordance with 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). The city water piping up to the closed cooling water system expansion tank, EDG jacket water expansion tank, closed cooling water system head tank, and nuclear services, as depicted on the city water license renewal drawing, is not required to meet any system intended functions under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3); therefore, it was not highlighted. Although not highlighted, the applicant has included the piping and valves within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), because of the potential for spatial interaction. The applicant also included the piping and valves in city water LRA tables for components subject to an AMR. The staff's concern described in RAI 2.3B.3.17-2(b) is resolved.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.17-2(c) acceptable because it adequately explained that the license renewal drawings reflect only the portions of systems within the scope of license renewal and subject to an AMR, under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). The city water piping up to the EDG jacket water expansion tank is not required to meet any system intended functions, in accordance with 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3); therefore, it was not highlighted. Although not highlighted, the applicant considered the piping and valves to be within scope, in accordance with 10 CFR 54.4(a)(2), because of the potential for spatial interaction. The applicant included the piping and valves in city water LRA tables for components subject to an AMR. City water, as a makeup water source to the EDG jacket water expansion tanks, is not required for the EDGs to perform their intended function. The staff's concern described in RAI 2.3B.3.17-2(c) is resolved.

2.3B.3.17.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the city water system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.18 IP3 Plant Drains

2.3B.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 describes the plant drains, which are passive fire protection features required for adequate protection of safety-related equipment from water damage in areas with fixed suppression systems. Plant drain components also prevent drain systems in areas with combustible materials from spreading fires into other areas of the plant. Some plant drains protect safety-related equipment from flooding effects.

Plant drain components are included in various systems, but grouped for this evaluation. SRP-LR Section 2.1.3.1 indicates that it is appropriate to group similar components from various plant systems into one consolidated review.

To prevent local flooding, areas with automatically operated fire protection have either gravity or pump drains to handle the maximum quantity of spray water. Plant drains protect safety-related equipment in the diesel generator rooms, electrical tunnels, PAB, and auxiliary feed pump room from the effects of Class III component failure. Either floor drains remove fire suppression water adequately or the water flows through other passages to protect safety-related equipment. When safety-related equipment may be lost as a result of inadvertent actuation of a fire system, redundant systems are available for safe shutdown.

The floor drains, fire water, and liquid waste disposal systems include plant drain components. Other sections do not address the waste disposal and liquid waste disposal systems. The floor drains system is not required for regulated events. Other systems provide drainage for flooding protection.

The liquid waste disposal system collects and processes liquid wastes from throughout the plant, including wastes from equipment drains, radioactive chemical laboratory drains, decontamination drains, demineralizer regeneration, and floor drains. The system also collects and transfers liquid drained from the RCS directly to the CVCS for processing. The system includes piping, valves, pumps, collection tanks, instruments, and controls. The system includes several containment penetrations and accompanying isolation components.

SER Section 2.3B.3.19 describes the floor drains system. SER Section 2.3B.3.11 describes the fire water system.

The plant drains system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the plant drains system performs functions that support fire protection.

A small number of liquid waste disposal system components are reviewed with the safety injection systems (LRA Section 2.3.2.4) and the primary water makeup systems (LRA Section 2.3.3.7).

LRA Tables 2.3.3-18-IP3 and 2.3.3-19-33-IP3 identify plant drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 and UFSAR Sections 9.6.2.3, 11.1, and 16.1.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.18, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.18-1, dated February 13, 2008.

2.3B.3.18.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the plant drains system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.3.19 IP3 Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2)

2.3B.3.19.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.19, the applicant described those systems that it included within the scope of license renewal because of their potential for physical interactions with safety-related components, as required by 10 CFR 54.4(a)(2). In this section, the applicant also described the components in these systems that are subject to an AMR. LRA Table 2.3.3-19-A-IP3 lists all of these systems and the LRA section in which the applicant evaluated these systems. LRA Section 2.3.3.19 describes in detail those systems, which are listed below, that do not have correlating LRA sections:

- ammonia/morpholine addition
- boron and layup chemical addition
- CL
- CW
- extraction steam
- floor drains
- gaseous waste disposal
- hydrazine addition
- heater drain/moisture separator drain/vent

- instrument air closed cooling
- lube oil
- low-pressure steam dump
- main turbine generator
- nuclear equipment drains
- process radiation monitoring
- primary plant sampling
- river water service
- main generator seal oil
- secondary plant sampling
- turbine hall closed cooling
- vapor containment hydrogen analyzer
- hydrogen (added by applicant by letter dated March 12, 2008)

Also in LRA Section 2.3.3.19, the applicant identified the following IP3 systems that it did not review under 10 CFR 54.4(a)(2) for spatial interaction because the applicant included all of the system's passive mechanical components under either 10 CFR 54.4(a)(1), another function of 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3):

- AFW
- control building HVAC
- CCW
- control rod drive
- control room HVAC
- engineered safeguards initiation logic
- isolation valve seal water
- RHR
- reactor protection and control
- SG
- SG level control
- security propane generator

The following are brief descriptions of IP3 systems that are included within the scope of license renewal and subject to an AMR, based only on the criterion of 10 CFR 54.4(a)(2).

Ammonia/Morpholine Addition System. The purpose of the ammonia/morpholine addition system is to provide ammonia or morpholine for pH control for the condensate system. LRA Table 2.3.3-19-1-IP3 identifies ammonia/morpholine addition system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

Boron and Layup Chemical Addition System. The boron and layup chemical addition system supplies chemicals to the SGs for chemistry control, even during periods of wet layup. Components in the boron and layup chemical addition system that support the AFW system pressure boundary are evaluated with the AFW systems (LRA Section 2.3.4.3). LRA Table 2.3.3-19-3-IP3 identifies boron and layup chemical addition system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Chlorination System. The chlorination system supplies sodium hypochlorite to limit microorganism fouling in the intake bays and river water systems. LRA Table 2.3.3-19-5-IP3 identifies chlorination system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Circulating Water System. The CW system supplies the condenser with Hudson River water to cool the steam exiting the low-pressure turbines. LRA Table 2.3.3-19-12-IP3 identifies CW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Extraction Steam System. The extraction steam system utilizes steam to preheat feedwater. LRA Table 2.3.3-19-18-IP3 identifies extraction steam system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Floor Drains System. The floor drains system removes any water collected in the nonradioactive floor drains in the turbine building, intake structure, and diesel generator building. LRA Table 2.3.3-19-19-IP3 identifies floor drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Gaseous Waste Disposal System. The gaseous waste disposal system collects, compresses, stores, samples, and releases gaseous waste from the primary and auxiliary systems. LRA Table 2.3.3-19-25-IP3 identifies gaseous waste disposal system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Hydrazine Addition System. The hydrazine addition system injects hydrazine into the secondary system for oxygen control. LRA Table 2.3.3-19-26-IP3 identifies hydrazine addition system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Heater Drain/Moisture Separator Drain/Vent System. The heater drain/moisture separator drain/vent system collects and transfers FW heater and moisture separator-reheater drainage to the suction of the main boiler FW pumps. LRA Table 2.3.3-19-27-IP3 identifies heater drain/moisture separator drains/vents system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Instrument Air Closed Cooling System. The instrument air closed-cooling system is a separate closed-loop cooling water system. This system supplies cooling water to the instrument air compressors and aftercoolers and rejects heat to the SW system. LRA Table 2.3.3-19-30-IP3 identifies instrument air closed-cooling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Lube Oil System. The lube oil system supplies oil for lubrication and control of the main turbine and the main boiler FW pumps and turbines. The lube oil system includes components that make up the main turbine controls. LRA Table 2.3.3-19-31-IP3 identifies lube oil system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Low-Pressure Steam Dump System. The low-pressure steam dump system prevents turbine overspeed by discharging steam from the high-pressure turbine exhaust to the condenser upon turbine trip. LRA Table 2.3.3-19-32-IP3 identifies low-pressure steam dump system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Main Turbine Generator System. The main turbine generator system, which receives steam from the SGs, converts a portion of the steam thermal energy to electricity, and supplies extraction steam for FW heating, consists of the turbine, generator, and instrumentation. This system does not include the control valves, moisture separator/reheaters, condensers, and generator cooling components. LRA Table 2.3.3-19-36-IP3 identifies main turbine generator system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Nuclear Equipment Drains System. The nuclear equipment drains system collects leakage and drainage from the primary plant equipment (e.g., charging pumps, containment fan cooler units). LRA Table 2.3.3-19-38-IP3 identifies nuclear equipment drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Process Radiation Monitoring System. The process radiation monitoring system monitors fluid streams for increasing radiation levels and generates an alarm or automatic action under abnormal conditions. LRA Table 2.3.3-19-40-IP3 identifies process radiation monitoring system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Primary Plant Sampling System. The primary plant sampling system obtains samples for laboratory analysis of reactor coolant and other reactor auxiliary systems during normal operation. The system also includes the post-accident reactor coolant sampling system, which obtains pressurized coolant samples following accidents. LRA Table 2.3.3-19-41-IP3 identifies primary plant sampling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

River Water Service System. The river water service system functionally supports the CW system to supply cooling water from the Hudson River to the main condensers. LRA Table 2.3.3-19-47-IP3 identifies river water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Main Generator Seal Oil System. The main generator seal oil system supplies oil to the main generator shaft seals to prevent hydrogen leakage from the generator into the turbine building. LRA Table 2.3.3-19-54-IP3 identifies seal oil system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Secondary Plant Sampling System. The secondary plant sampling system collects and transports samples to the sample room for laboratory analysis of the condensate, FW, and MS systems during normal operation. LRA Table 2.3.3-19-55-IP3 identifies secondary plant sampling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Turbine Hall Closed Cooling System. The turbine hall closed cooling system supplies cooling water to condensate pumps; heater drain pumps; main boiler feed pumps; and station, instrument, and administration building air compressors. LRA Table 2.3.3-19-58-IP3 identifies turbine hall closed cooling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Vapor Containment Hydrogen Analyzer System. The vapor containment hydrogen analyzer system monitors hydrogen and oxygen concentrations and post-LOCA hydrogen concentration in the containment atmosphere. Since a recent license amendment (License Amendment No. 228), hydrogen monitoring is no longer required as a safety function; however, the system remains available. LRA Table 2.3.3-19-59-IP3 identifies vapor containment hydrogen analyzer system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Hydrogen System (added by applicant by letter dated March 12, 2008). The hydrogen system provides hydrogen to the main generator for cooling and to the CVCS for the VCT cover gas. LRA Table 2.3.3-19-65-IP3 identifies hydrogen system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 and the following UFSAR sections that were associated with these systems:

• ammonia/morpholine addition[3]	Section 10.2.6.
• auxiliary steam and condensate return[4]	Section 9.6.4
• circulating water[3]	Section 10.2.4
• extraction steam[3]	Section 10.2
• floor drains[3]	Sections 9.6.2.3 and 16.1.3
• gaseous waste disposal[4]	Sections 11.1 and 14.2.3
• hydrazine addition[3]	Section 10.2.6
• heater drain/moisture separator drain/vent[3]	Section 10.2.6
• instrument air closed cooling[4]	Section 9.6.3
• main turbine generator[3]	Section 10.2
• nuclear equipment drains[3]	Section 6.7.1.2
• process radiation monitoring[4]	Section 11.2.3.1
• primary plant sampling[4]	Section 9.4
• river water service[3]	Section 10.2.4
• main generator seal oil[3]	Section 10.2.2
• secondary plant sampling[3]	Section 9.4
• vapor containment hydrogen analyzer[4]	Section 6.8
• boron and layup chemical addition[3]	—
• chlorination[3]	—
• lube oil[3]	—
• low pressure steam dump[3]	—
• turbine hall closed cooling[3]	—

For those systems receiving a simplified Tier 1 evaluation, the staff reviewed the applicable LRA and UFSAR sections using the evaluation methodology described in SER Section 2.3 and

[3] The staff conducted a simplified Tier 1 system review for these systems as described in SER Section 2.3
[4] The staff conducted a detailed Tier 2 system review for these systems as described in SER Section 2.3.

the guidance in SRP-LR Section 2.3. For those systems receiving a detailed Tier 2 evaluation, the staff reviewed the applicable LRA sections, applicable UFSAR sections, and license renewal drawings (system components are shown on other associated system drawings). Based upon information provided in the UFSAR and the LRA, the staff evaluated the system functions described in LRA Section 2.3.3.19 to verify that the applicant had not omitted from the scope of license renewal any components with intended functions pursuant to 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

The staff reviewed the list of IP3 systems the applicant identified in LRA Section 2.3.3.19 as not having any components in scope for 10 CFR 54.4(a)(2) for spatial interaction because they were already included in scope under 10 CFR 54.4(a)(1), functional (a)(2), or (a)(3). In RAI 2.3A.2.2-1, dated February 13, 2008, the staff asked the applicant to explain why it did not highlight on boundary drawings those piping segments directly attached to the IP2 CS system 10 CFR 54.4(a)(1) piping to indicate that they were included within the scope of license renewal. SER Section 2.3A.2.2.2 documents the staff's review of the applicant's response, dated March 12, 2008.

LRA Table 2.2-2-IP3 indicates that the hydrogen gas system is not within the scope of license renewal. This system, along with the nitrogen system, provides the VCT with gas for oxygen scavenging. Since the piping is directly connected to the VCT, the staff questioned whether the applicant should include the system within scope, in accordance with 10 CFR 54.4(a)(2), because of the potential for physical interaction between the nonsafety- and safety-related equipment. In its response, dated March 12, 2008, the applicant stated that the hydrogen system should be within scope, as required by 10 CFR 54.4(a)(2). The applicant amended the LRA to include the hydrogen system. SER Section 2.2B.3 documents the staff's review of the applicant's response, dated March 12, 2008.

During its review, the staff noted that the applicant did not specifically identify components on the license renewal drawings that are within the scope of license renewal under 10 CFR 54.4(a)(2). To determine that the applicant did not omit any components from scope under 10 CFR 54.4(a)(2), the staff used a sampling approach recommended in SRP-LR Section 2.3.3.1. In multiple RAIs, dated February 13, 2008, the staff asked the applicant to verify that it had included various segments of selected systems within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). This sampling approach allowed the staff to confirm that the applicant had properly implemented its methodology for identifying the nonsafety-related portions of systems with a potential to adversely affect safety-related functions, in accordance with 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that all components identified by the staff on the license renewal drawings are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR. Based on a review of its response, the staff finds that the applicant has adequately identified the components required to be within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR.

2.3B.3.19.3 Conclusion

For each system described above, the staff reviewed LRA Section 2.3.3.19, the applicable UFSAR section and license renewal drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found instances in which the applicant omitted systems and components that should have been included within the scope of license renewal. The applicant has satisfactorily resolved these issues as discussed in the preceding staff evaluation. On the basis of its review, the staff finds that, for all the systems identified in LRA Section 2.3.3.19 the applicant has appropriately identified the components within the scope of license renewal as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.4 Scoping and Screening Results: IP3 Steam and Power Conversion Systems

LRA Section 2.3.4 identifies the IP3 steam and power conversion systems SCs subject to an AMR for license renewal.

The applicant described the supporting SCs of the steam and power conversion systems in the following LRA sections:

- 2.3.4.1, "Main Steam"
- 2.3.4.2, "Main Feedwater"
- 2.3.4.3, "Auxiliary Feedwater"
- 2.3.4.4, "Steam Generator Blowdown"
- 2.3.4.5, "IP2 AFW Pump Room Fire Event"
- 2.3.4.6, "Condensate"

SER Sections 2.3B.4.1 through 2.3B.4.6, respectively, provide the staff's reviews of IP3 systems described in LRA Sections 2.3.4.1 through 2.3.4.6. The staff's findings for these systems are discussed below.

2.3B.4.1 IP3 Main Steam System

2.3B.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the MS system, which includes the auxiliary steam and condensate return, condenser air removal, gland seal steam, high-pressure steam dump, reactor protection and control, reheat steam, and turbine generator hydraulic control systems.

The MS system conducts steam from the four SGs inside the containment structure to the turbine generator unit in the turbine generator building. The system has four MS pipes, one from each SG to the turbine stop and control valves, which are interconnected near the turbine. Each steam pipe has an MSIV and a non-return valve outside the containment. Five code safety valves and one PORV are located on each MS line outside the reactor containment and upstream of the isolation and non-return valves. A flow venturi upstream of the isolation valve measures steam flow. Steam pressure is also measured upstream of the isolation valve. The MS system supplies steam to the main boiler FW pump turbines and the AFW pump turbine. The MS system includes the main boiler FW pump turbines and the turbine steam bypass and low-pressure steam dump systems, which channel excess steam flow to the condenser. The SGBD flowpath includes MS system components.

The auxiliary steam and condensate return system supplies auxiliary steam to plant components for IP3 heating and for the recovery of condensate via the condensate return lines. The system supplies steam for heating throughout the plant to room and area heating units, refueling water and primary water storage tanks, boric acid batch mixing tank, and other areas. The system also supplies minor steam loads, such as the condenser waterbox air ejectors. System supply by the house service boiler or steam reboiler includes heaters, air ejectors, steam distribution piping and valves, condensate return piping, valves, pumps, tanks, instruments, and controls.

The condenser air removal system removes air and non-condensable gases from the condensers to prevent gas buildup that would interfere with steam condensation. Each condenser has a four-element, two-stage air ejector with a separate inter-condenser and common after-condensers. Normal air removal requires one air ejector unit per condenser. For initial condenser shell-side air removal, three non-condensing priming ejectors use steam from the MS system supplied through a pressure-reducing valve. The system monitors the air ejector exhaust for radioactivity. In an SG leak and the subsequent presence of radioactively contaminated steam in the secondary system, this radiation monitor detects the radioactive non-condensable gases that concentrate in the air ejector effluent. A high-activity-level signal automatically diverts the exhaust gases from the vent stack to the containment.

The gland seal steam system supplies steam to the main turbine and boiler FW pump turbine gland seals. The system includes pressure-regulating valves and distribution piping and valves.

The high-pressure steam dump system provides an MS flowpath, bypassing the turbine to the main condenser when the turbine generator cannot accept the steam flow. Two MS bypass lines, one on either side of the turbine, divert excess steam from the four MS lines directly to the condensers, when necessary, before they reach the turbine stop valves. From each of the MS bypass lines, six lines, each with a bypass control valve, discharge into the condenser. The system includes the bypass control valves and its piping, controls, and instruments.

The reactor protection and control system monitors primary and secondary plant parameters and trips the reactor to protect the reactor core and RCS. The reactor protection and control system is primarily electrical, but includes a small number of mechanical instrumentation components that form parts of the SG secondary-side pressure boundary.

The reheat steam system supplies reheated steam to the low-pressure turbines and steam from the MS system to the main boiler FW pump turbines. Steam from the high-pressure turbine exhaust passes through the moisture separator reheaters, which remove moisture and reheat the steam by main steam extracted before it reaches the turbine MS stop valves. Part of the extracted main steam goes to the main boiler FW pump turbines. The system includes the moisture separator reheaters, piping, valves, instruments, and controls.

The turbine generator hydraulic control system directly controls the main turbine. The system has electrical and mechanical components of the turbine hydraulic control system, including the main turbine stop valves, and parts of the MS system pressure boundary for Appendix R safe shutdown.

The MS system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. In addition, the MS system performs functions that support fire protection and SBO.

Main steam components supporting the AFW system are reviewed with the AFW systems (LRA Section 2.3.4.3). Components containing air are reviewed with the compressed air systems (LRA Section 2.3.3.4). Condenser air removal system components in the containment penetration are reviewed with containment penetrations (LRA Section 2.3.2.5). Reactor protection and control components supporting the mechanical intended function are reviewed with the SGs (LRA Section 2.3.1.4).

The following LRA tables identify IP3 MS system component types that are within the scope of license renewal and subject to an AMR, as well as their intended functions:

- LRA Table 2.3.4-1-IP3
- LRA Table 2.3.3-19-2-IP3
- LRA Table 2.3.3-19-4-IP3
- LRA Table 2.3.3-19-24-IP3
- LRA Table 2.3.3-19-28-IP3
- LRA Table 2.3.3-19-35-IP3
- LRA Table 2.3.3-19-45-IP3
- LRA Table 2.3.3-19-57-IP3

2.3B.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1; UFSAR Sections 7.2, 9.6.4, 10.2, 10.2.1, 10.2.2, and 10.2.5; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.1, the staff 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 2.3B.4.1-1, dated December 7, 2007, the staff noted that license renewal drawings for the IP3 MS system show the following valves within the scope of license renewal and subject to an AMR: PCV-1134, PCV-1135, PCV-1136, PCV-1137, MS-1-31, MS-1-32, MS-1-33, MS-1-34, PCV-1120, PCV-1121, PCV-1122, PCV-1123, PCV-1124, PCV-1125, PCV-1126, PCV-1127, PCV-1128, PCV-1129, PCV-1130, PCV-1131. The staff also noted that these valves are air operated and have associated air cylinders and air tubing that were excluded from the scope of license renewal. Since some of these valves appear to rely on pressurized air (pneumatic operation) to change position and fulfill their intended function, the staff asked the applicant to explain why it did not include the instrument air system, its tubing, and associated SOVs to the valves in question within the scope of license renewal, in accordance with 10 CFR 54.4(a).

In its response dated January 4, 2008, the applicant stated that the air operators are active components; therefore, they are not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(i) and NEI 95-10, Appendix B. The applicant further explained that the SOVs and air tubing associated with the air-operated valves in the MS system are within the scope of license renewal, but are not subject to an AMR because the majority of the air-operated valves shown on the MS license renewal drawings as within the scope of license renewal fail to their required position for accident mitigation. As such, these valves do not require pressurized air to fulfill their intended function, and pressure boundary of the air tubing is not necessary. The applicant stated that the atmospheric dump valves and MSIVs are an exception. These valves close upon loss of air, but are credited with being re-opened, as necessary, in an accident scenario, using standby nitrogen in bottles or compressed air stored in accumulators. The applicant explained that components used to re-open the MS system valves are subject to an AMR.

Based on its review, the staff finds the response to RAI 2.3B.4.1-1 acceptable because the applicant adequately explained that, for most of the air-operated valves, a failure of the air supply system will not result in a loss of the intended function because the MS valves fail to their safe positions. This explanation is consistent with NEI 95-10, Revision 6, Section 5.2.3.1, which governs fail-safe components. For those air-operated valves that rely on an air supply system (i.e., those MS system valves that do not fail to their safe position), the passive pneumatic components (accumulator tanks, tubing, and valves) of those air-operated valves are included within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3B.4.1-1 is resolved.

2.3B.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the MS system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.4.2 IP3 Main Feedwater System

2.3B.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes the FW system, which transfers condensate and heater drain flow through the final stage of FW heating to the SGs. Two half-size, steam-driven main FW pumps increase the pressure of the condensate for delivery through the final stage of FW heating and the FW regulating valves to the SGs.

The main FW system includes the high-pressure FW heaters and piping and valves from the main feed pumps through the heaters to the SGs. The FW system also includes the main feed pump turbine drip tank drain pumps. The main FW pumps and services system supports the main FW system by increasing the pressure of the condensate for delivery through the final stage of FW heating and the FW regulating valves to the SGs.

The main FW system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the main FW system performs functions that support fire protection.

Feedwater system components supporting the AFW system are reviewed with such systems (LRA Section 2.3.4.3).

LRA Tables 2.3.4-2-IP3, 2.3.3-19-22-IP3, and 2.3.3-19-23-IP3 identify main FW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Section 10.2.6, and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.2, the staff 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 2.3B.4.2-1, dated December 7, 2007, the staff noted that license renewal drawings identify valves FCV-417-L, FCV-417, FCV-427-L, FCV-427, FCV-437-L, FCV-437, FCV-447-L, FCV-447, BF2-31, and BF2-32 for the IP3 main FW system as within the system evaluation boundary. The staff noted that, although the aforementioned valves are passive and long lived, they are not highlighted, indicating that they are not subject to an AMR. The staff asked the applicant to explain the valves' exclusion from an AMR.

In its response, dated January 4, 2008, the applicant explained that, although these FW system valves are located upstream of the containment isolation check valves in nonsafety-related piping, they are classified as safety related because of their active function to provide FW isolation. The applicant also stated that these valves "have no passive intended function for 54.4(a)(1) or (a)(3) because their failure would accomplish the safety function of isolating feedwater flow to the SGs." The applicant further stated that these valves perform their function with moving parts; therefore, in accordance with 10 CFR 54.21(a)(1)(i), they are not subject to an AMR and are not highlighted on the license renewal drawing. However, the applicant did indicate that the valves in question are within the scope of license renewal under

10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment; therefore, they are subject to an AMR.

The staff disagreed with the applicant's rationale that the valves do not have a passive intended function in accordance with 10 CFR 54.4(a)(1). The staff discussed the applicant's view during a telephone call on March 7, 2008. The applicant subsequently amended its RAI response by letter dated March 24, 2008, and reiterated that the FW system valves are safety related. The applicant also stated that, although not highlighted, these valves and the remainder of the FW system components on the associated license renewal drawing are in scope and subject to an AMR under 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment.

Based on its review, the staff finds the applicant's amended response to RAI 2.3B.4.2-1 acceptable because the applicant confirmed that the valves in question are within the scope of license renewal pursuant to 10 CFR 54.4(a), and subject to an AMR pursuant to 10 CFR 54.21(a)(1). Although the staff does not agree with the applicant's basis for determining how the valve bodies are subject to an AMR, the staff's concern is resolved because the AMR was performed, and the AMR results were provided in LRA Table 3.3.2-19-34-IP3. The staff's concern described in RAI 2.3B.4.2-1 is resolved.

In RAI 2.3B.4.2-2, dated December 30, 2007, the staff noted that UFSAR Section 14.2.5, Rupture of a Steam Pipe, states in the event of a main steam line break incident, the motor-operated valves (MOVs) associated with each of the feedwater regulating valves (FRVs) will close. UFSAR Section 14.2.5.1 states that redundant isolation of the main feedwater lines is necessary, because sustained high feedwater flow would cause additional cooldown; therefore, in addition to the normal control action which will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves (including the motor-operated block valves and low-flow bypass valves), trip the main feedwater pumps, and close the feedwater pump discharge valves. In addition, license renewal drawing 9321-20193 shows a "HIGH STEAM FLOW SI LOGIC" signal going to these motor-operated isolation valves. The motor-operated block valves shown on license renewal drawings are BFD-5's and BFD-90's for the main FRVs, and the low flow bypass regulating valves, respectively.

The feedwater isolation valves, BFD-5's and BFD-90's, are not included within the "system intended function boundary," nor are they highlighted on the license renewal drawings as having an intended function in accordance with 10 CFR 54.4(a)(1). By letter dated December 30, 2008, the staff requested the applicant to justify the exclusion of the BFD-5 and BFD-90 isolation valves from scope of license renewal in accordance with 10 CFR 54.4(a)(1). This issue was also identified as Open Item 2.3.4.2-1.

By letter dated January 27, 2009, the applicant stated that based upon a review of the qualifications of the isolation valves, the BFD-5 and BFD-90 valves are classified as nonsafety-related in the site component database and are located outside the Class I boundary [as corrected by letter dated March 13, 2009] on license renewal drawing LRA-9321-2019-0. As indicated in the IP3 UFSAR, these valves provide a backup isolation function for feedwater in the event of such accidents as a feedwater or steamline break. Credit for nonsafety-related components as a backup to safety-related components in mitigating breaks in seismically-qualified steam line piping is consistent with regulatory guidance provided in Standard Review Plan (NUREG-0800), Section 15.1.5, "Steam System Piping Failures Inside and Outside of

Containment (PWR)," and is also consistent with the allowance for feedwater regulating and bypass valves to be nonsafety-related, as discussed in NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR to NRR Staff." The applicant concluded that, consistent with the CLB, regulatory guidance, and NUREG-0138, the BFD-5 and BRD-90 valves are classified as nonsafety-related, and as such, meet the criteria to be included in scope for license renewal under 10 CFR 54.4(a)(2).

Based on the information provided by the applicant, the staff finds applicant's response to RAI 2.3B.4.2-2 acceptable because the BFD-5 and BFD-90 isolation valves are nonsafety-related components, and the valves are included in the scope for license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3B.4.2-2 is resolved. As a result, Open Item 2.3.4.2-1 is closed.

2.3B.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. The staff concludes that the applicant has appropriately identified the main FW system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.4.3 IP3 Auxiliary Feedwater System

2.3B.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 describes the AFW system, which supplies a flow of water from the CST to the SGs when the main FW pumps are unavailable. One steam turbine-driven and two electric motor-driven AFW pumps supply adequate feedwater to the SGs to remove reactor decay heat under all circumstances, including loss of power and normal heat sink (e.g., condenser isolation or loss of CW flow). The system can supply all four SGs. The steam-turbine-driven pump can be supplied from two of the SGs. The AFW system operates during plant startup at low power levels before the main FW pump is available. The system includes the AFW pumps, the turbine for the turbine-driven pump, piping from both CST and city water supply (an alternate source) through the pumps to the FW line supplying the SGs, valves, instruments, and controls. However, the system does not include the CST, which is part of the condensate transfer system.

The AFW system contains safety-related components relied on to remain functional during and following DBEs. In addition, the AFW system performs functions that support fire protection, ATWS, and SBO. Instrument air components included in the AFW system are reviewed with the compressed air systems (LRA Section 2.3.3.4).

LRA Table 2.3.4-3-IP3 identifies AFW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, UFSAR Sections 7.2.2 and 10.2.6, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review, the staff 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 2.3A.4.2-2, dated February 13, 2008, the staff noted that LRA Section 2.3.4.3 states that the AFW system has no intended function under 10 CFR 54.4(a)(2). However, the staff identified an instance in which components adjacent to safety-related components were not highlighted on license renewal drawings, but should have been considered for inclusion within the scope of license renewal because of their potential adverse spatial interaction, in accordance with 10 CFR 54.4(a)(2). For IP3, a license renewal drawing showed a section of piping extending from the AFW system piping (which includes valve SS-189) that was not highlighted. The staff asked the applicant to confirm that it evaluated the aforementioned components for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that the section of piping extending from the AFW system piping, which includes valve SS-189 is included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and is subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.4.2-2 acceptable because it adequately explained that the components in question are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR because of their potential to adversely interact spatially with safety-related equipment. The staff's concern described in RAI 2.3A.4.2-2 is resolved.

2.3B.4.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the AFW system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.4.4 IP3 Steam Generator Blowdown System

2.3B.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 describes the SGBD system, which includes the SGBD recovery and the SG sampling systems.

The SGBD system can control the concentration of solids in the shell side of the SGs. The system, which operates normally with a continuous blowdown and sample flow, has a drain connection and two blowdown connections (nozzles) at the bottom of each SG. Pipes from the connections (nozzles) join to form a stainless steel blowdown header. Four individual blowdown headers are routed from each SG to the PAB through containment isolation valves.

Downstream of the containment isolation valves, blowdown flow can be diverted to either the SGBD recovery system (during normal operation) or the blowdown flash tank. The SGBD recovery system consists of two heat exchangers, a filter and demineralizer package, piping, valves, and instrumentation.

The SG sampling system obtains representative secondary-side water samples for laboratory analysis of chemical and radiochemical conditions. The system has sample capability for each SG from its blowdown line inside containment. Each line to the sample room, where the liquid is cooled and the pressure reduced, has a containment penetration. Each sample is split into two routes—one to the sample sink for periodic chemical analysis and one to a conductivity cell, a radiation monitor, and then to the blowdown flash tank. The second line handles a continuous flow for constant conductivity reading and radiation monitoring.

The SGBD system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the SGBD system performs functions that support fire protection, ATWS, and SBO.

A small number of SGBD components are reviewed with the SW system (LRA Section 2.3.3.2). The SG sample heat exchangers (SG sampling system) are safety-related only for their cooling water pressure boundary function (heat transfer is not a required function). These heat exchangers are reviewed with the CCW system (LRA Section 2.3.3.3).

LRA Tables 2.3.4-4-IP3, 2.3.3-19-50-IP3, 2.3.3-19-51-IP3, and 2.3.3-19-52-IP3 identify SGBD system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 and UFSAR Sections 9.4.1 and 10.2.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.4.4.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SGBD system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3B.4.5 IP2 Auxiliary Feedwater Pump Room Fire Event (Not Applicable to IP3)

In the LRA, the applicant evaluated systems that in combination provide and support feedwater flow to the steam generators during a shutdown, and stated that the evaluation applies to IP2 only. During its review, the staff considered whether a similar evaluation was needed for IP3.

Similar to IP2, the IP3 AFW pump room contains redundant trains of safe shutdown systems and equipment separated by 20 feet with intervening combustibles. The NRC granted an exemption from the technical requirements of Section III.G.2 of 10 CFR Part 50, Appendix R on January 7, 1987. However, the AFW pump room fire event is not an issue at IP3 because the AFW pump room has area-wide coverage via automatic fire detection and a sprinkler system. This area is also equipped with manual hose stations and portable fire extinguishers. The NRC SER dated January 7, 1987, documents the staff's determination that fire protection features in the IP3 AFW Pump Room are adequate.

The staff finds that the applicant has demonstrated that the IP3 AFW pump room contains sufficient automatic fire suppression, the fire hazard within this area is low, and alternate shutdown capability exists. Therefore, an alternate feedwater flowpath is not required in the event of a fire in the IP3 AFW pump room.

2.3B.4.6 IP3 Condensate System

2.3B.4.6.1 Summary of Technical Information in the Application

LRA Section 2.3.4.6 describes the condensate system, which consists of components in the following systems: condensate, condensate polisher, condensate pump discharge, condensate pump suction, and condensate transfer.

The condensate system transfers condensate and low-pressure heater drainage from the condenser hotwell through the condensate polisher and five stages of FW heating to the main FW pump suctions. The condensate system is also the primary source of water to the AFW pumps. As part of the main condensate flowpath, three condensate pumps, arranged in parallel, take suction from the bottom of the condenser hotwells and discharge into a common header to the condensate polisher system. From the polisher system, a portion of the condensate passes through three steam jet air ejector condensers, arranged in parallel, and one gland steam condenser. The condensate passes through the tube sides of three parallel strings of two low-pressure FW heaters. The flows from these heaters combine in a common line, which then divides to flow into the remaining three strings of three low-pressure heaters. After the No. 5 FW heater, the three condensate lines join into a common header. The heater drain pump discharge enters this header and continues on to the suction of the main FW pumps.

The condensate system contains mostly valves, including a large number of small valves supplying condensate as gland seal water to various secondary plant valves. Within the condensate system, one valve has a safety function as part of the pressure boundary for the flowpath from the CST to the AFW pumps.

The condensate polishing system removes dissolved and suspended solids from the condensate to maintain FW quality required for the SGs. The polishers are within the existing condensate system between the condensate pumps and the first stage of FW heaters. The condensate polishing system consists of six service vessels, six condensate post-filters, three condensate booster pumps, piping, valves, instrumentation, and controls.

The condensate pump discharge system supports sampling of the condensate pump discharge. Components in this system code include the small sampling piping and valves at the discharge of the condensate pumps.

The condensate pump suction system supplies water to the condensate pumps from the main condenser. Components in this system code include the expansion joints, piping, and valves between the condenser and the condensate pumps.

The condensate transfer system transfers condensate from the condenser to the suction of the main boiler FW pumps and from the CST to the AFW pumps. This system includes condensate system components from the condensate pumps to the suction of the main boiler FW pumps (except the condensate polishers and their support equipment), the CST and piping and components to the AFW pump suction header, the main condensers, the condensate and low-pressure FW heaters, piping, valves, instruments, controls, and other condensate system components.

The condensate system contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the condensate system potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the condensate system performs functions that support fire protection and SBO.

Components that support the pressure boundary of the AFW system flowpath are evaluated with the AFW systems (LRA Section 2.3.4.3).

LRA Tables 2.3.3-19-6-IP3, 2.3.3-19-7-IP3, 2.3.3-19-8-IP3, 2.3.3-19-9-IP3, and 2.3.3-19-14-IP3 identify condensate system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6, UFSAR Section 10.2.6, and license renewal drawings (condensate system components are shown on drawings of other system) using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.4.6.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the condensate system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those 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:

- containment buildings
- water control structures
- turbine buildings, auxiliary buildings, and other structures
- bulk commodities

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SCs within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus allowed the staff to confirm that there were no omissions of SCs that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the information in the LRA for all structures sought to determine whether the applicant had identified, in accordance with 10 CFR 54.4, the components and supporting structures, for structures that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived SCs were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections, focusing 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 to determine whether the applicant had omitted from the scope of license renewal SCs with license renewal intended functions in accordance with 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all license renewal intended functions, in accordance with 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether (1) the functions are performed with moving parts or a change in configuration or properties or (2) the SCs are subject to replacement after a qualified life or specified time period, in accordance with 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

During its review of LRA Section 2.4, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for structures. Therefore, the staff issued issue-specific RAIs by letter dated January 28, 2008, to determine or confirm whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a) to structures and structural components. The applicant provided its responses to the staff's RAIs by letter dated February 27, 2008, and supplemented it by Amendment 3 to the LRA, dated March 24, 2008. The applicant further provided responses to the staff's followup RAIs by letter dated June 11, 2008, and submitted Amendment 5 to the LRA, dated June 11, 2008.

The following discussion describes the staff's RAI related to the scoping of structures in LRA Section 2.4, and the applicant's responses. Relative to the applicant's scoping and screening results for structures documented in LRA Section 2.4, the staff also reviewed LRA Table 2.2-3, which lists the plant-level structures that are within the scope of license renewal, and LRA Table 2.2-4, which lists the plant-level structures that are not within the scope of license renewal. The staff performed these reviews to determine if there were any omissions in the structures scoped at the plant-level and to verify that all the scoped structures were addressed in LRA Section 2.4.

Based on its review of the UFSAR, the staff identified certain structural components that do not appear to be included in LRA Tables 2.2-3 and 2.2-4 or in LRA Section 2.4. In the first part of RAI 2.4-1, the staff requested that the applicant explain whether or not the structures listed below are within the scope of license renewal and subject to an AMR:

(i) pipe penetration tunnel (Reference: IP2 final safety analysis report (FSAR), Section 1.11.4.10)

(ii) liquid waste storage building (Reference: IP3 FSAR, Sections 16.1.2 and 9.6.4)

(iii) condenser tube withdrawal/removal pit (Reference: IP3 FSAR, Chapter 1; Site Plan Drawing 64513; and IP2 FSAR, Figure 10.2-3)

(iv) fuel oil storage tank and its foundation at Buchanan Substation (this tank provides backup fuel oil for emergency diesels and gas turbines)

In its response to RAI 2.4-1, Item (i), dated February 27, 2008, the applicant stated that the pipe penetration tunnel is located in the IP2 fan house and is included within the scope of license renewal as part of the fan house structure, identified in LRA Table 2.2-3 as "fan house (IP2)." The staff verified that LRA Table 2.2-3, as well as LRA Section 2.4.3, identified the "fan house (IP2)" as a structure. Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.4-1, Item (i), is resolved.

In its response to RAI 2.4-1, Item (ii), dated February 27, 2008, the applicant stated that the liquid waste storage building is located within the administration building. The applicant stated that the liquid waste storage building is not within the scope of license renewal because it does not perform a license renewal intended function, as required by 10 CFR 54.4(a). Therefore, LRA Table 2.2-4 lists the liquid waste storage building as part of the line item "administration building (IP3) (service admin complex)." The staff verified that LRA Table 2.2-4 lists "administration building (IP3) (service admin complex)" as a structure that is not within the scope of license renewal. The staff further confirmed from UFSAR Section 16.1.2 for IP3 that the liquid waste storage building is a seismic Class III component of the waste disposal system. Its failure will not result in offsite doses in excess of the limits required by 10 CFR Part 20, "Standards for Protection against Radiation." Based on the above, the staff finds that the liquid waste storage building does not perform a license renewal intended function, as detailed in 10 CFR 54.4(a). Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.4-1, Item (ii), is resolved.

In its response to RAI 2.4-1, Item (iii), dated February 27, 2008, the applicant stated that the condenser tube withdrawal/removal pits are located in the lower level of the turbine buildings. The applicant included these components in the scope of license renewal as part of the structures identified in LRA Table 2.2-3 as "turbine building and heater bay (IP2)" and "turbine building and heater bay (IP3)." The staff verified that LRA Table 2.2-3, as well as LRA Section 2.4.3, identifies the "turbine building and heater bay (IP2)" and "turbine building and heater bay (IP3)" as structures. Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.4-1, Item (iii), is resolved.

In its response to RAI 2.4-1, Item (iv), dated February 27, 2008, the applicant stated that the "fuel oil storage tank foundation" at Buchanan Substation is within the scope of license renewal and included within the line item "gas turbine generator No. 2 and 3, enclosure and fuel tanks foundation" in LRA Table 2.2-3. The staff verified that LRA Table 2.2-3, as well as LRA Section 2.4.3, identifies the line item "gas turbine generator No. 2 and 3, enclosure and fuel tanks foundation." Further, the staff verified that the fuel oil storage tanks are scoped and screened as a mechanical fuel oil system component in LRA Section 2.3.3.13 and not in LRA Section 2.4.3. The staff finds that the applicant's response addressed the staff's question and, therefore, is acceptable. The staff's concern described in RAI 2.4-1, Item (iv), is resolved.

In its response, dated February 27, 2008, the applicant concluded that, as a result of this RAI, the applicant did not have to revise LRA Tables 2.2-3 or 2.2-4. The staff finds that the applicant appropriately confirmed and justified the license renewal scoping of the specific structures and structural components that were in question in the first part of RAI 2.4-1; therefore, the applicant's response to the first part of RAI 2.4-1 is acceptable. The staff's concerns described in the first part of RAI 2.4-1 are resolved. SER Section 2.4.3.2 discusses the second part of RAI 2.4-1.

Based on the information provided in the LRA, the RAI response discussed above, and the UFSAR, the staff concludes that, in LRA Section 2.4, the applicant identified, without omissions, the structures that are within the scope of license renewal for IP2 and IP3, in accordance with 10 CFR 54.4(a).

2.4.1 Containment Buildings

2.4.1.1 Summary of Technical Information in the Application

LRA Section 2.4.1 describes the containment buildings, which completely enclose the entire reactor and the RCS and ensures that essentially no leakage of radioactive materials to the environment would result even if a design basis LOCA occurs. The reactor containment structure is a seismic Class I, reinforced concrete vertical right cylinder with a flat base and hemispherical dome. A welded steel liner attached to the inside face of the concrete shell ensures a high degree of leak-tightness. The liner has accommodations for penetrations and personnel access. For IP2, the steel liner plate is covered by polyvinyl chloride insulation in a stainless steel jacket. For IP3, the steel liner plate is covered by urethane foam insulating material covered with gypsum board and a stainless steel jacket and backed with a fire-retardant paper on the unexposed side. The containment liner is anchored to the concrete shell by stud anchors. The bottom liner plate on top of the reinforced concrete base mat is covered with additional concrete, the top of which forms the floor of the containment. Internal structures consist of equipment supports, shielding, reactor cavity and canal for fuel transfer, manipulator crane, containment crane, and miscellaneous concrete and steel for floors and stairs. All internal structures are supported on the mat except equipment supports which are secured to the intermediate floors.

The containment buildings contain safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the containment buildings potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the containment buildings perform functions that support fire protection.

LRA Table 2.4-1 identifies containment buildings component types, grouped by material (steel/other metals, concrete, other materials) within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1; IP2 UFSAR Sections 1.2.2, 1.11.2, and 5.1.2; and IP3 UFSAR Sections 1.3.5, 5.1.2, and 16.1.2 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4, "Scoping and Screening Results: Structures."

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that it had not omitted any passive and long-lived SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.4.1, the staff 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 2.4.1-1, dated January 28, 2008, the staff noted that UFSAR Section 5.1.2.1 (IP2 and IP3) states that the containment structure serves as both a biological shield and a pressure boundary component. Since the biological shield function was not explicitly listed among the intended functions for containment buildings in LRA Section 2.4.1 and LRA Table 2.4-1, in RAI 2.4.1-1, the staff requested that the applicant clarify and include biological shield function as an intended function for containment buildings in the LRA.

In its response, dated February 27, 2008, the applicant stated that the biological shield function is an intended function for the IP2 and IP3 containment buildings. The applicant further stated that this intended function is implicit in the definition of the shelter or protection function *EN* in LRA Table 2.0-1, which includes "radiation shielding." The staff verified that the definition of the *EN* function in LRA Table 2.0-1 does include "radiation shielding" within parenthesis. The staff finds the response to be acceptable since it refers to an intended function. Therefore, the applicant's response to RAI 2.4.1-1 has adequately addressed the issue raised by the staff and is acceptable. The staff's concern described in RAI 2.4.1-1 is resolved.

A lack of clarity in LRA Table 2.4-1 prompted the staff to seek clarification. In RAI 2.4.1-2, the staff requested that the applicant confirm and/or clarify whether the following components associated with the containment buildings are included as components subject to an AMR in LRA Table 2.4-1 or justify their exclusion. For the components that are subject to an AMR, the applicant was requested to provide the appropriate AMR results in LRA Section 3.5.

(i) primary shield wall around the reactor

(ii) control rod drive missile shield

(iii) retaining wall at the equipment hatch entrance and its missile shield (fixed and removable)

(iv) blowout shield plug

(v) insulation for the containment building liner (limits temperature rise in liner under accident conditions)

(vi) protective coating for liner

(vii) water proofing around fuel transfer tube

(viii) waterproof membrane for containment wall against backfill

(ix) reactor cavity seal ring (see UFSAR Figures 5.1-6 and 5.1-7)

(x) Seismic Class I debris screens at containment purge (Ref. UFSAR Section 5.1.4.2.4)

(xi) stud anchors that anchor the containment liner plate to the concrete shell

In its response, dated February 27, 2008, the applicant addressed each of the components identified in the RAI with respect to whether they are subject to an AMR, as indicated below:

(i) The primary shield wall around the reactor is included as part of "beams, columns, interior walls, slabs" listed in LRA Table 2.4-1. AMR results are provided in Table 3.5.2-1.

(ii) The control rod drive missile shield is included with the line item "missile shields" listed in Table 2.4-4. AMR results are provided in Table 3.5.2-4.

(iii) The retaining wall at the equipment hatch entrance is included as part of "beams, columns, interior walls, slabs" listed in LRA Table 2.4-1. AMR results are provided in Table 3.5.2-1. The equipment hatch missile shield (fixed and removable) is included with the line item "missile shields" listed in Table 2.4-4. AMR results are provided in Table 3.5.2-4.

(iv) Components/commodities identified in scope that provide missile protection are addressed in LRA Section 2.4-4 and Table 2.4-4. The "blowout shield plug" is included with the line item "missile shields" listed in LRA Table 2.4-4. AMR results are provided in Table 3.5.2-4.

(v) The insulation for the containment building liner is included in Table 2.4-1 with line item "liner insulation jacket." AMR results are provided in Table 3.5.2-1.

(vi) Protective coatings are not in the scope of license renewal because they do not perform an intended function. Their failure will not prevent satisfactory accomplishment of a safety function.

(vii) The waterproofing material around the fuel transfer tube is not in scope. Waterproofing membranes have no license renewal intended function.

(viii) The waterproof membrane for containment wall against backfill is not in scope. Waterproofing membranes have no license renewal intended function.

(ix) The reactor cavity seal ring identified in UFSAR Figures 5.1-6 and 5.1-7 has no license renewal intended function. This component is not safety-related and is not required to demonstrate compliance with regulations identified in 10 CFR 54.4(a)(3). Failure of the seal ring will not prevent satisfactory accomplishment of a safety function. The seal is provided to prevent leakage during refueling operations. This component is not listed in LRA Table 2.2-4 since it does not meet the threshold of a major structural component.

(x) The seismic Class I debris screens at containment purge identified in UFSAR Section 5.1.4.2.4 do not perform a license renewal intended function. The primary containment isolation valves in the containment purge and pressure relief exhaust ducts are closed during normal plant operation. Failure of the screens will not prevent the ventilation systems from performing their intended function. These components are not required during design basis accidents or for any regulated event. The structural support of this component is included in scope and is included with line item "Structural steel: beams, columns, plates, trusses" listed in LRA Table 2.4-1.

(xi) The stud anchors that anchor the containment liner plate to the concrete shell are included in the line item "anchorages/embedments" listed in LRA Table 2.4-4. AMR results are provided in Table 3.5.2-4.

In its response, dated February 27, 2008, the applicant has confirmed/clarified the screening of each of the components in question and provided justification of the components that are not subjected to an AMR. The staff finds the applicant's response to Items (ii), (iv), and (xi) acceptable because the applicant explicitly clarified that the components in question are within the scope of license renewal and are subject to an AMR. The staff finds the applicant's response to Items (vii), (viii), and (x) acceptable because the applicant explicitly clarified that the components in question do not have an intended function that meets any of the criteria in 10 CFR 54.4(a). Therefore, the staff finds that the applicant's response to RAI 2.4.1-2 is acceptable, with the following exceptions with regard to the response to Items (i), (iii), (v), (vi) and (ix) of RAI 2.4.1-2. In a follow-up RAI to RAI 2.4.1-2, dated May 12, 2008, the staff requested the applicant to clarify/address these exceptions. The applicant provided clarification responses to the follow-up RAI items by letter dated June 11, 2008. The follow-up RAI items and their resolution are discussed below.

- With regard to Item (i), the response stated that Primary Shield Wall is included as part of line item "Beams, columns, interior walls, slabs" in LRA Table 2.4-1. The staff noted that walls with lesser safety-significance, such as pressurizer shield, ring wall, and cylinder walls, have been listed as separate items in LRA Table 2.4-1. Considering that the primary shield wall is subjected to a more severe environment (high temperature and radiation exposure) and has a much higher safety-significance than the general interior wall, the staff requested, in a follow-up RAI dated May 12, 2008, that the applicant include the primary shield wall as a separate line item in LRA Table 2.4-1, to make its inclusion in the scope of license renewal and its consideration as being subject to AMR, explicitly clear.

  In its response, dated June 11, 2008, the applicant added the primary shield wall as a separate concrete component item in LRA Tables 2.4-1 and 3.5.2-1 with the appropriate intended functions. By doing so, the applicant has explicitly included the primary shield wall as a component subject to AMR. Therefore, the staff finds the response acceptable. The staff's evaluation of the AMR results for the primary shield wall is documented in SER Section 3.5.

- With regard to Item (iii), the response stated that the retaining wall is included as part of line item "Beams, columns, interior walls, slabs" in LRA Table 2.4-1. The staff noted that the retaining wall at the equipment hatch entrance is an exterior wall and is subjected to a different environment than the interior wall. Therefore, in a follow-up RAI dated May 12, 2008, the staff requested the applicant to explicitly include the retaining wall at the equipment hatch entrance in LRA Table 2.4-1 as a separate line item.

  In its response, dated June 11, 2008, the applicant added the equipment hatch entry retaining wall (exists for IP2 only) as a separate concrete component item in LRA Tables 2.4-1 and 3.5.2-1 with the appropriate intended functions. By doing so the applicant has explicitly included the IP2 retaining wall at the equipment hatch entrance as a component subject to AMR. Therefore, the staff finds the response acceptable.

- With regard to Item (v), the response stated that liner plate insulation is included with line item "Insulation Jacket" in LRA Table 2.4-1. The staff noted that materials for the insulation jacket and the insulation itself are not the same. The jacket is stainless steel but the insulation is PVC for IP2 and Urethane foam covered with gypsum board for IP3 (UFSAR Section 5.1). The insulation itself is not included in LRA Table 2.4-1 or LRA Table 2.4-4; nor are these materials identified in LRA Sections 3.5.2.1.1 or 3.5.2.1.4. They also were not addressed in the response to RAI 2.4.4-2. In a follow-up RAI dated May 12, 2008, the staff requested the applicant to appropriately address the scoping, screening, and AMR results for these in-scope insulation materials in the LRA.

  In its response, dated June 11, 2008, the applicant stated that the IP2 containment liner plate PVC insulation and IP3 containment liner urethane insulation are encapsulated within stainless steel jacketing (IP2 UFSAR Section 6C.8.4, and IP3 UFSAR Section 5.5) and are not exposed to containment atmosphere. The only visible and exposed parts of the insulation are the stainless steel jacketing. The aging management review results in LRA Table 3.5.2-1 for the liner plate insulation pertain to the stainless steel jacketing. The applicant added that the containment liner plate insulation within the jacketing is in scope and subject to aging management review for providing shelter and protection to the containment liner plate. The PVC and urethane insulation materials have no aging effects in the air-indoor environment and, therefore, no aging management program is necessary.

  In the above response, the applicant has clarified that, for both IP2 and IP3, the containment liner plate insulation within the jacketing is within the scope of license renewal and subject to AMR but does not need aging management since there are no aging effects in its protected environment. Based on the above response, it is the staff's understanding that the PVC and urethane insulation are encapsulated within the stainless steel insulation jacketing forming one composite unit, and the AMR results in LRA Table 3.5.2-1 for the line item "liner plate insulation jacket" includes the encapsulated insulation, which is exposed to an indoor air environment that does not promote aging effects. The staff finds that the applicant's response addressed the staff's concern with regard to scoping and screening of the liner insulation and, therefore, is acceptable.

- With regard to Item (vi), the response stated that protective coatings for the containment liner are not in scope because they do not perform an intended function. Staff noted that, although protective coating on the containment liner does not directly perform a license renewal function, it prevents degradation of the liner if properly maintained. Section XI.S8 of NUREG-1801, Volume 2, which is the AMP for protective coatings, recommends maintenance of the protective coatings to avoid clogging of the sumps. The GALL Report states that, if protective coatings are relied upon to manage the effects of aging, the structures monitoring program is to include provisions to address protective coating monitoring and maintenance (Item 25 in Table 5 of NUREG-1801, Volume 1). Therefore, in a follow-up RAI dated May 12, 2008, the staff requested the applicant to provide justification for excluding the protective coating on the containment liner from the scope of license-renewal and from being subject to an AMR.

  In its response, dated June 11, 2008, the applicant stated that the liner plates of IP2 and IP3 containment are provided with protective coatings. The applicant stated that, in response to Generic Safety Issue (GSI)-191, "Assessment of Debris Accumulation on PWR Sump Performance," the applicant's Civil/Structural Engineering group visually inspects coatings in the vapor containment building during refueling outages. Sump clogging for IP2 and IP3 was evaluated, and the evaluation results were provided by Entergy, Inc., in letter dated September 1, 2005, in response to NRC generic letter 2004-02, "Potential impact of debris blockage on emergency recirculation during design basis accidents at pressurized water reactors."

The applicant further added that the GALL Report states that, if protective coatings are relied upon to manage the effects of aging, the structures monitoring program should include provisions to address protective coating monitoring and maintenance. The applicant stated that, as indicated in LRA Table 3.5.1, Item 3.5.1-25, IP2 and IP3 containment liner protective coatings are not relied upon to manage the effects of aging. As shown in LRA Table 3.5.2-1, aging effects of liner plate and integral attachments are managed by the Containment Inservice Inspection-IWE and Containment Leak Rate Test programs for license renewal. Accordingly, the protective coating on the containment liner is not within the scope of license renewal and, therefore, is not subject to aging management review.

In the above response, the applicant clarified that inspection commitments of protective coatings and sump clogging evaluations were addressed as part of its response to the NRC's GSI-191 issue. The applicant reiterated that the aging effects of the liner plate are managed by the containment inservice inspection program per IWE and the Appendix J Containment Leakage Rate Testing Program, and that protective coatings are not relied upon to manage the effects of aging of the liner. Therefore, the staff accepts the applicant's determination that the protective coating on the containment liner may be considered outside the scope of license renewal and not subject to AMR. The staff finds the response acceptable.

- With regard to Item (ix), the response stated that the reactor cavity seal ring has no license renewal intended function. The staff notes that the reactor cavity seal ring is a flood barrier (FLB) to preclude borated water leaks through the seal and thereby prevent accumulation of borated water in the gap between the reactor vessel and the primary shield wall, which could induce corrosion of the reactor vessel and its supports as well as cause degradation of the primary shield wall concrete. Considering the above, in a follow-up RAI dated May 12, 2008, the staff requested the applicant to provide justification for excluding the reactor cavity seal from the scope of license-renewal and from being subject to an AMR.

  In its response, dated June 11, 2008, the applicant stated that the reactor cavity seal ring is a nonsafety-related component and it has no license renewal intended function pursuant to 10 CFR 54.4(a). Therefore, the reactor cavity seal is not within the scope of license renewal nor subject to AMR. The applicant specifically explained that the reactor cavity seal ring is installed prior to filling the refueling cavity to allow for fuel handling operations and that plant procedures ensure proper installation to preclude leakage during refueling operations. The applicant added that, even if the seal were to leak during the time the refueling cavity is filled, sump pumps in the cavity beneath the reactor vessel would prevent water accumulation in the gap between the reactor vessel and the primary shield wall.

  The applicant further stated that plant operating experience does not indicate that leakage from the reactor cavity seal ring has caused corrosion of the reactor vessel or its supports; nor has it caused degradation of primary shield wall concrete. Further, aging management programs shown in LRA Tables 3.1.2-1 and 3.5.2-1 will manage the effects of aging from corrosion, if any, of the reactor vessel and its supports and will manage degradation of the interior concrete walls from exposure to borated water leakage during refueling.

Based on the above response, the staff understands that the reactor cavity seal is a nonsafety-related component installed during each refueling outage prior to flooding of the reactor cavity for refueling operations using procedures to ensure a leaktight installation. Also, the applicant's operating experience has not indicated any degradation of the reactor vessel, its supports, and the primary shield wall attributable to leakage through the reactor cavity seal. Further, the applicant has procedures/programs in place to manage any effects even if the seal were to leak during refueling operations. Therefore, the staff accepts the applicant's determination that the seal does not perform a license renewal intended function pursuant to 10 CFR 54.4(a) and, therefore, the reactor cavity seal is not in scope of license renewal nor subject to AMR. The applicant's response resolved the staff's concern.

Based on the discussion above of the applicant's clarifying responses, the staff finds the applicant's response to RAI 2.4.1-2 acceptable.

In RAI 2.4.1-3, dated January 28, 2008, the staff requested that the applicant confirm whether the component identified as "Structural Steel: beams, columns, plates, trusses" in LRA Table 2.4-1 includes bracings, welds, and bolted connections. The applicant also was requested to confirm whether the pressurized channel shrouds used at liner welded joints (including those at penetrations) are included in a structure/commodity group, or to justify their exclusion from an AMR. In addition, the applicant was requested to confirm whether the components identified as "bellows penetrations" in LRA Table 2.4-1 include the refueling bellows, if refueling bellows are used at IP2 and IP3.

In its response, dated February 27, 2008, the applicant stated that the component identified as "Structural Steel: beams, columns, plates, trusses" in LRA Table 2.4-1 includes bracing and welds associated with the component. The applicant further clarified that bolted connections for structures/components are addressed in LRA section 2.4.4 and Table 2.4-4. The applicant stated that the pressurized channel shrouds associated with liner welded joints (including those at penetrations) are not addressed as a separate component group. They are considered integral to the components listed as "liner plate and integral attachments" and "Electrical penetration sleeves" and "Mechanical penetration sleeves" in LRA Table 2.4-1. The applicant stated that components identified as "bellows penetrations" in LRA Table 2.4-1 do not include "refueling bellows." The applicant further clarified that bellows penetrations in LRA Table 2.4-1 are associated with containment piping penetrations and that refueling bellows are not a feature of the IP2 or IP3 design.

The staff finds that the applicant's response adequately addressed the staff's questions with regard to the stated components and, the response to RAI 2.4.1-3 is acceptable, subject to resolution of the additional clarifications requested below with regard to bellows. With regard to bellows penetrations, the applicant's response stated that the bellows penetrations in LRA Table 2.4-1 are associated with containment piping penetrations and that refueling bellows are not a feature of the IP2 or IP3 design. In the follow-up RAI dated May 12, 2008, the staff requested the applicant to further describe the types of piping penetration bellows in each unit. Also, the staff requested the applicant to clarify if there are transfer canal bellows (with the number in each unit) at Indian Point and if they are in-scope of license renewal or not, with justification.

In its response, dated June 11, 2008, the applicant stated that IP2 and IP3 containment penetrations consist of a sleeve embedded in the concrete and welded to the containment liner. The applicant explained that differential expansion between a sleeve and one or more hot pipes passing through it is accommodated by using a nickel alloy or stainless steel bellows-type expansion joint between the outer end of the sleeve and the piping outside of the containment wall. The applicant added that details of the containment penetrations and bellows for each unit are shown in UFSAR Figures 5.1-30 (IP2) and 5.1-12 (IP3).

The applicant stated that, for each unit, a fuel transfer tube is provided for fuel movement between the refueling transfer canal in the reactor containment and the spent fuel pit. The fuel transfer tube consists of a 20-in. stainless steel pipe installed inside a 24-in. pipe. The applicant added that two bellows-type expansion joints (one inside containment and one in the spent fuel pit) are provided on the tubes to compensate for any differential movement between the two pipes and other structures. Figure 5.1-31 of IP2 UFSAR and Figure 5.1-14 of IP3 UFSAR show details of the fuel transfer tube and bellows for each unit. These penetration bellows are within the scope of license renewal and subject to an AMR. They are listed as "bellows penetration" in LRA Tables 2.4-1 and 3.5.2-1.

In its above response, the applicant confirmed that, in addition to the piping penetrations bellows, the two fuel transfer tube bellows for each unit were in scope of license renewal and subject to AMR and were included as part of line item "bellows penetration" in LRA Table 2.4-1. The staff finds that the response addressed the staff's question with regard to the types of bellows that were scoped and screened for license renewal. Therefore, the response is acceptable.

During its review of components listed as "Polar Crane, rails and girders" and "Manipulator Crane, crane rails and girders" in LRA Table 2.4-1, the staff determined that additional information was needed to complete its review. In RAI 2.4.1-4, dated January 28, 2008, the staff requested that the applicant confirm whether the column structure; bridge and trolley of the polar crane; and the bridge, trolley and mast of the manipulator crane were screened-in as subject to an AMR. The staff also requested that the applicant confirm whether fasteners and rail hardware associated with the polar crane and manipulator crane are within scope of license renewal and subject to an AMR; and if they were excluded, the staff requested that the applicant provide a justification. The staff also requested that the applicant indicate whether there were any other hoists and lifting devices (e.g. for the reactor vessel head and reactor internals) that should be included as components within the scope of license renewal and subject to an AMR; and if so, the staff requested that the applicant provide scoping, screening, and AMR results relevant to the LRA.

In its response, dated February 27, 2008, the applicant stated that the column structure; bridge and trolley of the polar crane; and the bridge, trolley and mast of the manipulator crane are screened-in as subject to an AMR. The applicant indicated that these components are subparts of "crane, rails and girders." The applicant stated that fasteners ("structural bolting") and rail hardware ("component support") associated with the polar crane and manipulator crane are within the scope of license renewal and subject to an AMR. The applicant indicated that these components are addressed in LRA Section 2.4.4, "Bulk Commodities." The applicant clarified that there were no hoists or lifting devices, other than those already identified in the LRA, that perform a license renewal intended function.

Because the applicant stated that the structures and components in question are subject to an AMR, the staff finds that the applicant adequately addressed the staff's questions; therefore, the response to RAI 2.4.1-4 is acceptable. The staff's concern described in RAI 2.4.1-4 is resolved.

Because of a lack of clarity in LRA Table 2.4-1 regarding components listed as Equipment Hatch and Personnel Lock, in RAI 2.4.1-5, dated January 28, 2008, the staff requested that the applicant clarify whether the flange double-gaskets, hatch locks, hinges, and closure mechanisms that help prevent loss of sealing/leak-tightness for these listed hatches were included within the scope of license renewal and subject to an AMR. The staff also requested that the applicant provide scoping, screening, and AMR results as appropriate or justify their exclusion.

In its response, dated February 27, 2008, the applicant stated that the flange double-gaskets, hatch locks, hinges, and closure mechanisms for the equipment hatch and personnel lock are within the scope of license renewal. The applicant clarified that the double gasket seals are included under the line item "equipment hatch and personnel lock seal" in LRA Table 2.4-1, and are subject to AMR. The AMR results are provided in Table 3.5.2-1. The applicant stated that hatch locks, hinges, and closure mechanisms are active components and are, therefore, not subject to aging management review as discussed in LRA Table 3.5.1, Line Item 3.5.1-17. The applicant added that satisfactory performance of these active components is demonstrated through routine testing under the Containment Leak Rate Program as required by Section 3.6.2 of the IP2 and IP3 Technical Specifications.

The staff finds that the applicant has adequately addressed the staff's concern with regard to the flange double-gaskets for the hatches in question. However, the response stated that the hatch locks, hinges, and closure mechanisms are active components and, therefore, not subject to AMR as discussed in LRA Table 3.5.1, Line Item 3.5.1-17. The staff noted that these components are passive during plant operation, during which time they are (and need to remain) in a closed position and are an integral part of the pressure boundary. Considering the above, in a follow-up RAI, dated May 12, 2008, the staff requested the applicant to provide the justification for excluding the hatch locks, hinges, and closure mechanisms from the scope of license-renewal and from being subject to an AMR.

In its response, dated June 11, 2008, the applicant stated that the IP2 and IP3 hatch locks, hinges, and closure mechanisms are in scope of license renewal. However, since they perform their functions with moving parts or change in configuration, they are not subject to AMR. The applicant added that consistent with NUREG-1801, Volume 1, Revision 1, Table 5, Item 17, their leaktightness in the closed position is demonstrated through routine testing under the containment leakage rate test program as required by IP2 and IP3 Technical Specifications (Reference LRA Table 3.5.1, Line Item 3.5.1-17). Since the applicant's response clarified that, in the closed position, the hatch locks, hinges, and closure mechanisms are considered integral to the hatch itself, whose leaktightness is demonstrated by routine local leak rate testing under the Containment Leakage Rate Test Program, the staff finds the response acceptable.

2.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI and follow-up RAI responses to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine if the applicant failed to identify any SCs subject to an AMR. The staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the containment buildings SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Water Control Structures

2.4.2.1 Summary of Technical Information in the Application

LRA Section 2.4.2 describes the water control structures, which include:

- discharge canal and outfall structure
- intake structure (IP1, IP2, IP3) and intake structure enclosure building (IP3)
- service water pipe chase (IP3)
- service water valve pit (IP2 and IP3)

The discharge canal and outfall structure, located west of the IP2 and IP3 turbine buildings, extends from the IP1 turbine building and carries SW system discharge to the river. Three IP3 backup SW pumps, which provide cooling water from the discharge canal in the unlikely event of damage to the SW intake structure, are supported on a slab spanning the walls of the canal. The SW pipe chase, a concrete structure enclosing the SW line, spans across the discharge canal. The discharge canal wall portion adjacent to the SW pipe chase is seismic Class I and part of the ultimate heat sink. The outfall structure enhances mixing of cooling water and river water to minimize thermal impact on the river. The discharge port gates can be adjusted mechanically to control fluid discharge velocity. The outfall structure does not support a license renewal function as defined by 10 CFR 54.4 and hence is not in the scope of license renewal.

The IP1 intake structure (also known as the screenwell house) is a seismic Class III structure located adjacent to the wharf and west of the station on the riverbank. It houses electrical components required for the alternate safe shutdown system, which is credited in the Appendix R safe shutdown analysis. The lower portion contains the IP1 intake, which houses the river water pumps that support IP2 SW. The structure is a reinforced concrete frame supported by a massive concrete substructure. Exterior walls of the intake structure are of concrete brick construction. The north and south ends of the structure are covered by a reinforced concrete roof slab.

The IP2 intake structure (also known as the screenwell structure) is west of the site, below grade at the Hudson River bank, and is open to the river on the west side. The IP3 intake structure (also known as the screenwell structure) is west of the containment structure. Each structure houses six CW pumps (each in a separate reinforced concrete compartment), six SW pumps (a SW bay enclosure protects the IP3 pumps), traveling and fixed screens, and screen wash equipment. On the east side of each structure, the SW strainer pit houses SW strainers, screen wash piping, and the strainer control panel. Both the SW strainer pit and the SW bay enclosure are seismic Class I.

The intake structure enclosure building located west of the containment structure provides an upper separate enclosure for the IP3 intake structure and protects CW and SW system components from the weather. Dampers located in the roof system release excess heat during normal operations. The intake structure enclosure consists of a single story steel-framed super-structure with exterior metal siding and ventilation panels.

The IP3 SW pipe chase, which protects SW lines that span the discharge canal and the SW valves and piping, is a reinforced concrete structure attached to the discharge canal wall. The discharge canal wall portion adjacent to the SW pipe chase is seismic Class I.

SW valve pits at the west side of the IP2 and IP3 heater bay buildings protect SW components in IP2 and IP3 intake structures. IP3 has an additional SW valve pit on the north end of the IP3 heater bay building to back up the SW pumps. The SW valve pits are underground reinforced concrete structures covered by structural steel plate welded to I-beams at ground level. The additional SW valve pit for IP3 has a precast concrete roof.

The water control structures contain safety-related components relied upon to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the water control structures potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the water control structures perform functions that support fire protection.

LRA Table 2.4-2 identifies water control structures component types, grouped by material (steel/other metals, concrete), within the scope of license renewal and subject to an AMR as well as their intended functions.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 and UFSAR Section 8.3 for IP2 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.4.2, the staff 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 2.4.2-1, dated January 28, 2008, the staff noted that LRA Table 2.4-2 does not include the debris wall, fixed coarse screens, fine mesh traveling screens, and gates at the intake structure. Further, the table does not include metal decking, metal siding, grating, and ventilation panels for the intake structure enclosure; nor does it include manhole, ladder, and sump of the SW valve pit. The staff requested that the applicant confirm whether or not these components should be included within the scope of license renewal and subject to an AMR and, if so, to provide scoping, screening and AMR results. If not, the staff requested the applicant to justify their absence from LRA Table 2.4-2. The applicant also was requested to clarify whether the "structural steel" component in LRA Table 2.4- 2 includes, among other items, beams, plates, and welded/bolted connections.

In its response, dated February 27, 2008, the applicant stated that the debris wall, fixed coarse screens, fine mesh traveling screens, and gates at the intake structure are not safety-related and are not required to demonstrate compliance with 10 CFR 54.4(a)(3). The applicant stated that the system design is such that failure of these components will not prevent satisfactory accomplishment of a safety function. However, their support structures, being integral to the intake structure in some cases (e.g., embedded guides and steel supports), are included in the "structural steel" category listed in LRA Table 2.4.2. The applicant stated that metal siding for the intake structure enclosure is not safety-related and is not required to demonstrate compliance with 10 CFR 54.4(a)(3). The applicant added that failure of the metal siding component will not prevent satisfactory accomplishment of any safety function. The applicant stated that in-scope grating, decking, and ladders are bulk commodities addressed in LRA Table 2.4-4. The ventilation panels for the intake structure enclosure are addressed as "vents and louvers" and listed in LRA Table 2.4-4. Furthermore, the applicant stated that manholes are included in LRA Table 2.4-3. The sump of the SW valve pit is integral to the in-scope SW valve pit; thus, it is not listed as a separate item. The applicant clarified that the "structural steel" component type in LRA Table 2.4-2 includes columns, beams, plates, and their welded connections. Structural bolting is included as a bulk commodity and listed in LRA Table 2.4-4.

In reviewing the response to RAI 2.4.2-1, the staff also reviewed the discussion on the "Service Water System" and "Tornado Design Criteria" in Sections 9.6.1 and 16.2, respectively, of the IP3 UFSAR. Based on the description in these UFSAR sections, the SW supply is assured by redundancy of two supply lines, four intakes and screens, and six pumps, of which only two pumps, one intake and screen, and one supply line are required for prolonged shut-down. Further, the backup SW system provides an additional source of service water independent of the intake structure. The existence of these redundancies in the SW system confirms the applicant's statement, in the RAI response, that failure of the intake structure components noted in the RAI, which are part of the SW system, will not prevent satisfactory accomplishment of the safety function of the SW system. However, in the response, the applicant stated that in-scope grating, decking, and ladders are bulk commodities addressed in LRA Table 2.4-4. Since this is a generic statement, in a follow-up RAI, dated May 12, 2008, the staff requested the applicant to clarify if the specific components in question that were identified in the RAI (i.e. metal decking and grating of the intake structure enclosure and ladder of the service water valve pit) are included in the scope of license renewal, and subject to AMR as bulk-commodities addressed in LRA Table 2.4-4.

In its response, dated June 11, 2008, the applicant stated that metal decking and grating of the intake structure enclosure and ladder of the service water valve pit have license renewal intended functions as defined by 10 CFR 54.4(a)(2) and, therefore, they are in scope of license renewal and subject to an AMR. The applicant added that these structural components are included in LRA Table 2.4-4, line item "Stairway, handrail, platform, grating, decking, and ladders." Since the applicant explicitly clarified that the specific structural components identified in the RAI were subject to an AMR, the staff finds the response acceptable.

Based on the above response to RAI 2.4.2-1 and to the follow-up RAI, and the descriptions in Section 9.6.1 and Section 16.2 of the IP3 UFSAR, the staff finds that the applicant has adequately addressed and/or clarified the scoping and screening of the specific structural components identified in the RAI. Therefore, the applicant's response to RAI 2.4.2-1 is acceptable.

The staff also requested additional information in RAI 2.4.2-2, dated May 12, 2008, regarding other structural components. In Part (a) of RAI 2.4.2-2, the staff noted that LRA Table 2.2-3 and LRA Section 2.4.2 include "discharge canal and outfall structure" as being within the scope of license renewal. The description in LRA Section 2.4.2, in the second paragraph under the subtitle "Discharge Canal and Outfall Structure," states that the outfall structure does not support a license renewal function and, therefore, is not in scope. The staff requested the applicant to explain why the "outfall structure" was included in LRA Table 2.2-3 and LRA Section 2.4.2. The staff requested the applicant to discuss this inconsistency and take appropriate action in scoping the outfall structure.

In Part (b) of RAI 2.4.2-2, because of a lack of clarity in the description in LRA Section 2.4.2 with regard to the discharge canal, the staff requested the applicant to confirm/clarify if (i) the entire discharge canal is considered within the scope of license renewal and subject to AMR or (ii) only the portion adjacent to/supporting the service water pipe chase, and the portion supporting and including the slab on which the Unit 3 service water backup pumps are mounted, are within the scope of license renewal and subject to an AMR.

In its response to Part (a) of RAI 2.4.2-2, dated June 11, 2008, the applicant stated that the "outfall structure" is included in LRA Table 2.2-3 and LRA Section 2.4.2 as part of line item "discharge canal and outfall structure" because this line item is the name of one continuous structure that includes the discharge canal and the outfall structure. The only portion that is within the scope of license renewal is the discharge canal. The applicant reiterated that the description in LRA Section 2.4.2, in the second paragraph under the subtitle "Discharge Canal and Outfall Structure," states that "[t]he outfall structure does not support a license renewal function as defined by 10 CFR 54.4 and, therefore, is not in scope." The applicant added that this statement specifically addresses exclusion of the outfall structure portion of the structure from the scope of license renewal and AMR. The staff finds the response acceptable because the applicant clarified that only the discharge canal is within the scope of license renewal; the outfall structure portion of the "discharge canal and outfall structure" is not within the scope of license renewal.

In its response to Part (b) of RAI 2.4.2-2, dated June 11, 2008, the applicant stated that the entire discharge canal is within the scope of license renewal and subject to AMR. Since the response clarified that the entire discharge canal is conservatively included as being in scope of license renewal and subject to AMR, the staff finds the clarification provided by the applicant acceptable.

2.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI and follow-up RAI responses, and description of related structural components to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine if the applicant failed to identify any SCs subject to an AMR. Again, the staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the water control structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Turbine Buildings, Auxiliary Buildings, and Other Structures

2.4.3.1 Summary of Technical Information in the Application

LRA Section 2.4.3 describes the turbine buildings, auxiliary buildings, and other structures:

- Appendix R diesel generator foundation, fuel oil tank vault, switchgear and enclosure (IP3)
- auxiliary feedwater pump building (IP2, IP3)
- boric acid evaporator building (IP2)
- city water storage tank foundation and meter house
- condensate storage tanks foundation (IP2, IP3)
- containment access facility and annex (IP3)
- control buildings (IP2, IP3)
- diesel generator buildings (IP2, IP3)
- electrical tunnels (IP2, IP3)
- emergency lighting poles and foundations
- fan houses (IP2, IP3)
- fire pump house (IP2)/fire protection pump house (IP3)
- fire water storage tank foundation (IP2, IP3)
- fuel storage buildings (IP2, IP3)
- gas turbine generator Nos. 1, 2, and 3 enclosure and fuel tank foundation (includes gas turbine substation switchgear structures and foundation)
- maintenance and outage building elevated passageway (IP2)
- manholes and duct banks
- new station security building
- nuclear service building (IP1)
- power conversion equipment building (IP3)
- PABs (IP2, IP3)
- primary water storage tanks foundation (IP2, IP3)
- radiation monitoring enclosure (IP2)
- refueling water storage tanks foundation (IP2, IP3)
- security access and office building (IP3)

- superheater building (IP1)
- superheater stack (IP1)
- transformer/switchyard support structures
- transmission towers (SBO recovery path) and foundations
- turbine building (IP1, IP2, IP3) and heater bay (IP2, IP3)
- utility tunnel
- waste holdup tank pit (IP2, IP3)

The Appendix R diesel generator, fuel oil tank vault, and switchgear are located in separate, adjacent enclosures in the yard area north of the AFW pump room. The Appendix R diesel generator, fuel oil tank vault, and switchgear support a power supply sufficient to allow the plant to be brought to cold shutdown in a loss of offsite power coincident with a fire causing the loss of all three EDGs or their distribution systems.

The IP2 AFW pump building in the shield wall area between the shield wall and the IP2 containment building is a seismic Class I structure that protect the Class I AFW pumps. The MS lines also located in this building are supported by the structural steel framing.

The IP3 AFW pump building in the shield wall area between the shield wall and the IP3 containment building also includes the shield wall area enclosure. It is a seismic Class I structure that protects the Class I AFW pumps and MS lines located in this area.

The boric acid evaporator building is a seismic Class I reinforced concrete structure supported by the roof slab of the IP2 waste hold-up tank pit. The exterior walls are of concrete and concrete block construction. Portions of the concrete walls are removable. Over the concrete block portion is light-weight roofing over metal decking and over the concrete walls is a concrete slab.

The city water storage tank and meter house is a source of water for the AFW system for both IP2 and IP3 and of emergency water for SI, RHR, and charging pumps. The city water storage tank foundation supports the storage tank safety function. The meter house shelters and protects the storage tank components. A free-standing, 1,500,000-gallon vertically cylindrical carbon steel city water storage tank is supported by a reinforced concrete spread footing foundation on rock. The meter house is a single-story concrete brick and steel structure with a concrete roof slab.

Two separate reinforced concrete slab foundations support the condensate storage tanks for IP2 and IP3.

The containment access facility and annex adjacent to the PAB is a handling area for contaminated material and a personnel access to containment. The containment access facility and annex is Class III except for the seismic Class I structural steel portion interfacing with the PAB. The containment access facility and annex has structural steel framing supported on the PAB roof floor slab and insulated metal siding.

The control buildings house the central control room, cable spreading room, and other safety-related equipment and components. The IP2 control building adjacent to the IP2 turbine building on the west and the superheater building on the south contains both the IP1 and IP2 control rooms. It is a multi-story Class I steel framed structure with north and east exterior walls of insulated metal-sandwich panels. Floor slabs are composite-type construction, concrete over steel beam. The IP3 control building is a multi-story Class I concrete structure with concrete and concrete brick exterior is adjacent to the IP3 turbine building on one end and the diesel generator building on the south. Both structures are founded on bedrock.

The seismic Class I IP2 diesel generator building consists of a reinforced concrete foundation on bedrock, a prefabricated rigid steel superstructure with exterior insulated metal siding, and a solid, corrugated metal roof. The diesel generators rest on reinforced concrete foundations supported by the structure's main slab. A concrete shield wall on the west side serves as missile protection between the control panel and diesels. The IP3 diesel generator building is a single-story reinforced concrete structure on a concrete slab supported on bedrock. Each diesel generator building houses three safety-related diesel generators. Each diesel has separate underground storage vaults, integral to its building, for fuel oil tanks. Foundations for the fuel oil tanks are the same as for the structure.

The electrical tunnels are partially below-grade, seismic Class I reinforced concrete structures that contain electrical cable, conduit, and cable trays that support plant operations. The IP2 electrical tunnel running eastward from the east side of the control building is attached to the south side of an east-west retaining wall. The elevation of the lower slab of the tunnel slopes from the control building up to the PAB. The tunnel then turns northward past the west side of the PAB to the electrical penetration area adjacent to the IP2 containment building. The IP3 electrical tunnels run from the control building past the PAB to the containment penetration vault. The electrical tunnels consist of two seismic Class I reinforced concrete conduits, one above the other. Both the upper and lower tunnels are eight feet wide by eight feet high.

Pole-mounted security lighting around the perimeter of the plant site provides emergency lighting in an Appendix R fire and a loss of offsite power by illuminating ingress and egress. Each emergency light pole is a single-pole steel structure supported by a reinforced concrete foundation.

Each fan house is a seismic Class I structure containing the piping penetration area. Safety-related valves in the piping penetration area may be used to achieve safe shutdown. Each fan house building is a multi-story reinforced concrete and masonry block wall structure founded on bedrock. A steel superstructure on top of each building supports the roof framing system. The IP2 fan house southeast of the IP2 containment structure and between the IP2 containment, the IP2 PAB, and the IP2 fuel storage building is isolated from the containment structure and the PAB. Its east wall is common with the west wall of the fuel storage building. The IP3 fan house southeast of the IP3 containment structure and between the IP3 containment, the IP3 PAB, containment access facility, and the IP3 fuel storage building is isolated from the containment structure and the PAB. Its east wall is common with the west wall of the fuel storage building and its south wall is common to the containment access facility annex.

The IP2 fire protection pump house (also known as diesel fire pump house) houses the main diesel firewater pump and protects fire protection system components. The structure is of structural steel framing with exterior insulated metal siding and a composite metal roof. The foundation is a reinforced concrete slab on grade. The IP3 fire protection pump house contains the electric motor-driven fire pump, the diesel-driven fire pump, and equipment for an adequate source of fire water. The structure is a reinforced concrete and concrete block wall construction with a concrete roof slab. The foundation is a reinforced concrete slab on bedrock.

The IP2 fire water storage tank (also known as suction tank) foundation is the main support for the 300,000-gallon fire water storage tank. Water for the dedicated diesel-driven fire pump for normal operations comes from the tank. The IP3 fire water storage tank foundations are the main supports for two 350,000-gallon fire water storage tanks. The tanks and their piping, electrical, and instrumentation systems are the source of fire protection system water and IP3 makeup water treatment.

For IP2 and IP3, the fuel storage building is designed to handle and store both spent and new fuel and supports the spent fuel crane and other fuel-handling equipment. In addition, the floor of IP2 provides support for a single-failure-proof gantry crane. Each structure is located adjacent to but separate from its containment building.

The gas turbine generator No. 1 enclosure and tank foundation are seismic Class III structures providing shelter and protection from the elements for gas turbine No. 1 and its associated equipment. Gas turbine No. 1 is located adjacent to the Unit 1 turbine building and supports no license renewal function; however, the associated switchgear components and fuel supply tank provide support for the SBO/Appendix R diesel generator set. The gas turbine No. 1 enclosure consists of structural steel framing with exterior metal siding on a reinforced concrete slab. The fuel tank foundation is a reinforced concrete spread footing which supports the fuel tank supplying the SBO/Appendix R diesel.

The gas turbine generators Nos. 2 and 3 enclosure is a seismic Class III structure that shelters and protects the equipment from the elements. The gas turbine Nos. 2 and 3 enclosure located at the Buchanan substation houses gas turbine generators Nos. 2 and 3 and their switchgear equipment. The switchgear and associated components within the structure support offsite power recovery following station blackout. The gas turbine Nos. 2 and 3 fuel tank foundation supports the fuel tank, an alternate source of EDG fuel. These fuel tanks shared by IP2 and IP3 are credited for minimum EDG fuel oil inventory. If the EDGs require the reserves in these tanks, the contents can be transported by tanker truck.

The gas turbine substation switchgear structures and foundation support equipments required to support offsite power recovery following station blackout. It consists of a reinforced concrete slab that supports the substation and switchgear support structures. Component equipment is anchored by welding or bolting to embedments in the concrete slab.

The maintenance and outage building and elevated passageway are seismic Class II structures used by maintenance and outage personnel. The structures are southeast of the IP2 containment structure, across from the PAB, and adjacent to the fuel storage building. The building has two major floors and an elevated passageway for access to the PAB. A safety-related conduit routed through one end of the building near the bridge connects the maintenance and outage building to the PAB.

Manholes and duct banks throughout the applicant's yard allow underground routing of cables and piping. These structural components are of reinforced and non-reinforced concrete.

The new station security building east of the IP1 containment structure provides offices for personnel and contains the security generator credited as a source of backup power to the station security lighting system. For IP2, this lighting illuminates exterior ingress and egress in an Appendix R fire and a loss of offsite power.

The IP1 nuclear service building adjacent to but separated from the IP1 containment structure protects alternate safe shutdown system components in support of IP2. These components consist of cables in conduit for various systems: chemical and volume control, CCW, RHR, and SI systems. The structure contains treatment and decontamination facilities and examination rooms for site personnel.

The IP3 power conversion equipment building houses power conversion system components.

The IP2 PAB is a seismic Class I structure housing safety injection pumps, component cooling pumps, heat exchangers, and RHR pumps. The IP3 PAB houses components required for recirculation (*e.g.*, component cooling pumps, heat exchangers, and SI and RHR pumps).

The IP2 and IP3 primary water storage tank foundations are the main supports for the 165,000-gallon primary water storage tank for each unit. The tanks supply demineralized water for the primary water makeup systems.

The IP2 radiation monitoring enclosure houses radiation monitors R46, R49 and R53. Monitors R46 and R53 monitor the SW return from all containment fan cooler units.

For both IP2 and IP3, the RWST foundation is the main support for the 350,000-gallon RWST. The tank supplies borated water to the refueling canal, SI pumps, RHR pumps, and the containment spray pumps for a LOCA.

The IP3 security access and office building located west of the service admin complex provides offices for personnel and contains the security generator credited as a source of backup power to the station security lighting system. For IP3, this lighting illuminates exterior ingress and egress in an Appendix R fire or a loss of offsite power.

The IP1 superheater building is adjacent to but physically separated from the control building. The superheater stack is located on top of the superheater building. The structure contains the technical support center, provides office area for personnel, supports alternate safe shutdown system components, and houses a safety-related battery room.

The IP1 superheater stack on top of the superheater building carries exhaust from the superheaters and also supports a ventilation duct carrying exhaust from the containment structure. Failure of the stack could result in damage to the IP2 control building, the EDG building, and in-scope IP3 structures. To minimize this risk, the applicant shortened the stack and reinforced its support structure to satisfy IP3 tornado protection criteria.

The offsite power source required to support SBO recovery actions is fed through one of the station auxiliary transformers. Specifically, the path includes the 138kV and 345kV switchyard circuit breakers feeding either station auxiliary transformers.

The transformer/switchyard support structures physically support the station auxiliary transformers and the other switchyard components in the SBO recovery path. These support structures include the transformer foundations and support steel, transformer pothead foundations and support steel, and switchyard breaker foundations.

Transmission towers (SBO recovery path) and foundations are parts of the path to restore offsite power.

The IP1 turbine building is an extension of the IP2 turbine building and is integrally attached to the superheater building and the IP2 turbine building. The structure is classified as seismic Class III but was analyzed to ensure that there is no potential for gross structural collapse as a result of a design basis event. Equipment and components on the IP1 operating floor have been removed and the supporting systems for these components are not in service. The facility houses the station blackout/Appendix R diesel and two fire water pumps, along with their associated components relied upon in the site's safe shutdown analysis. The building is constructed of heavy structural steel framing with steel supported reinforced concrete slabs forming the floor area. Crane rails located within IP1 extending the entire length of the structure also provide support for IP2. The building's exterior face is constructed of metal-sandwich panels and concrete brick.

The IP2 turbine building and heater bay extension of the IP1 turbine building is similar to IP1 and is seismic Class III. Although the turbine building and heater bay are seismic Class III structures, they were analyzed for potential gross structural collapse as a result of a design-basis event. Attached to the superheater building and the IP1 turbine building, the building houses the IP2 turbine generator, FW heaters, and their supporting systems as well as cabling, switchgear, and other SBO/Appendix R diesel equipment.

The IP3 turbine building and heater bay is a seismic Class III structure that houses the turbine generator and its auxiliaries. The structure is designed not to affect Class I structures.

The utility tunnel is a seismic Class III structure. The tunnel shelters and protects the city water supply piping for AFW backup water and other miscellaneous functions. The utility tunnel is a rectangular reinforced concrete structure founded on rock.

The IP2 waste holdup tank pit is adjacent to the refueling water tank and its top slab supports the boric acid evaporator building. The IP3 waste holdup tank pit, two structures joined to form a single structure, is adjacent to the primary water storage tank and the radioactive machine shop. The waste holdup tank pits house liquid waste holdup tanks which are the collection points for liquid radwaste. A sump services the water tanks.

The turbine buildings, auxiliary buildings, and other structures contain safety-related components relied upon to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the turbine buildings, auxiliary buildings, and other structures potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the turbine buildings, auxiliary buildings, and other structures perform functions that support fire protection and SBO.

LRA Table 2.4-3 identifies turbine buildings, auxiliary buildings, and other structure component types, grouped by material (steel/other metals, concrete), within the scope of license renewal and subject to an AMR as well as their intended functions.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 and IP2 UFSAR Sections 1.3.8, 1.11.4.12, 1.11.6, 7.2.4.1.4, and 9.5.2, and IP3 UFSAR Sections 8.4, 9.6.2, 9.6.2.9, and 11.1.2.1, using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived SCs subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.4.3, the staff 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 the second part of RAI 2.4-1, dated January 28, 2008 (the first part of RAI 2.4-1 is addressed in SER Section 2.4), the staff noted that the structure identified as "Gas Turbine Substation Switchgear Structures and Foundation" in LRA Table 2.2-3 was not included in the structures listed at the beginning of the subsection "Description" of LRA Section 2.4.3. The staff requested that the applicant address the scoping and screening of these structures or clarify where they were addressed in the LRA.

In the last paragraph of its response to RAI 2.4-1, dated February 27, 2008, the applicant stated that the "Gas Turbine Substation Switchgear Structures and Foundation" area is addressed in LRA Section 2.4.3, subsection titled "Description" under "Gas Turbine Generator No. 1, 2 and 3 Enclosure and Fuel Tank Foundation." The staff verified that a description of switchgear structures and foundation was included in the subsection in Section 2.4.3 describing the gas turbine generators No. 1, 2 and 3 enclosure and fuel tank foundations, as stated by the applicant. The staff finds the applicant's response acceptable subject to further clarification as requested in the follow-up RAI, dated May 12, 2008.

Because of a lack of clarity in LRA Table 2.4-3, and the applicant's response to RAI 2.4-1 with regard to switchgear structures and foundation, the staff sought clarification regarding which specific structural components in Table 2.4-3 cover the switchgear structures and foundation. The staff noted that the component line item "foundations" in LRA Table 2.4-3 does not list "switchgear structures" in the structure list provided within parenthesis.

In its response, dated June 11, 2008, the applicant stated that the switchgear foundation is listed in LRA Table 2.4-4, as equipment pads/foundations. Since the applicant clarified that the switchgear foundations are included as a concrete bulk commodity item as part of line item "equipment pads/foundation" in LRA Table 2.4-4, and the embedments to which the switchgear equipment is anchored are included as part of bulk commodity line item "anchorages/embedments" in LRA Table 2.4-4, the staff finds the response acceptable.

In RAI 2.4.3-1, dated January 28, 2008, the staff noticed the following in the LRA with regard to the fuel storage buildings:

(i) LRA Section 2.4.3 states that the fuel storage buildings have the following intended functions pursuant to 10 CFR 54.4(a)(1) and (a)(2): "Maintain integrity of nonsafety-related components such that safety functions are not affected by maintaining pool water inventory (Units 2 and 3)."

(ii) LRA Section 2.1.2.2, "Screening of Structures," states that the screening of structural components and commodities was based primarily on whether they perform an intended function.

(iii) LRA Table 3.5.2-3, "Turbine Building, Auxiliary Building, and Other Structures, Structural Components and Commodities (IP2 and IP3)," identifies structural components subject to aging management based on materials of construction and intended functions for components of structures, including the fuel storage buildings.

(iv) The intended functions listed in LRA Table 3.5.2-3 (e.g., pressure boundary, missile barrier, and shelter or protection) agree with the intended functions listed in LRA Table 2.0-1, "Intended Functions: Abbreviations and Definitions." However, the intended functions for the fuel storage building listed in LRA Section 2.4.3 do not agree with the listed intended functions in LRA Tables 2.0-1 and 3.5.2-3.

With reference to the above, the staff noted in the RAI that, pursuant to 10 CFR Part 54.21, the LRA must identify and list those SCs subject to an AMR. The staff requested that the applicant clarify the LRA Section 2.4.3 description of the intended function(s) of the fuel storage building components, using the list of intended functions from LRA Table 2.0-1. The staff added that, to satisfy the requirements of 10 CFR Part 54.21, the clarification must be adequate to reasonably identify the fuel storage building structural components subject to an AMR by the component or commodity, material of construction, and intended functions listed in LRA Table 3.5.2-3.

In its response, dated February 27, 2008, as supplemented in LRA Amendment No. 3, dated March 24, 2008, the applicant stated that the intended functions listed in LRA Tables 2.0-1 and 3.5.2-3 are component intended functions, which are determined during the screening process. The intended functions in LRA Section 2.4.3, in contrast, are the intended functions of the structure in its entirety and are determined during the scoping process. The applicant explained that the scoping process determines whether or not the structure has an intended function (i.e., providing containment or isolation to mitigate post-accident offsite doses, or providing support or protection to safety-related equipment), whereas the screening process identifies those components that support the structure intended function(s) via specific component intended functions (i.e., providing shelter and protection or providing support for safety-related equipment). The structure and system level functions that are assessed against the scoping requirements of 10 CFR Part 54.4 are not intended to match the component level functions defined in LRA Table 2.0-1. While similarities exist between the terminology used for component intended functions versus structure intended functions, a direct correlation between the structure intended functions in LRA Section 2.4 and the component intended functions in the tables in LRA Section 3.5 does not exist. The applicant clarified that the structure level intended functions of the fuel storage buildings are to: (a) maintain integrity of nonsafety-related components such that safety functions are not affected by maintaining pool water inventory, and (b) provide support and protection for safety-related equipment within the scope of license renewal. The applicant also provided a tabulation of component level intended functions (as defined in LRA Table 2.0-1) supporting each of the two structure level intended functions for the fuel storage buildings.

In its response, the applicant used a broader structure level intended function concept in the scoping process and supplemented that by more detailed component level intended functions for the structural components during the screening process. Because the applicant 1) has clarified the structure level intended functions of the fuel storage buildings, and 2) provided a tabulation of the structural component intended functions for each of the two structure level intended functions (as defined in LRA Table 2.0-1), the staff finds the applicant's response acceptable. Therefore, the staff's concern described in RAI 2.4.3-1 is resolved.

In RAI 2.4.3-2, dated January 28, 2008, the staff noted that, in LRA Section 2.4.3, the top of the spent fuel pit wall forms the north wall of each unit's fuel building. The staff further noted that UFSAR Figure 1.2-4 (IP2), "Cross Section of Plant," indicates that at least part of the fuel building exterior wall is below grade. LRA Table 2.4-3 lists pressure boundary as an intended function for the concrete component "exterior walls" but does not list pressure boundary as an intended function of the concrete component "exterior walls-below grade," representing the fuel building wall. The staff requested that the applicant update LRA Table 2.4-3 to include the pressure boundary intended function for the spent fuel pit wall that is below grade or provide justification for excluding this intended function.

In its response, dated February 27, 2008, the applicant stated that it agrees that the spent fuel pit wall below grade also performs a pressure boundary intended function. The applicant revised LRA Tables 2.4-3 and 3.5.2-3 to include the pressure boundary intended function for exterior walls below-grade which includes the spent fuel pit wall. The staff finds the applicant's response adequately addresses the staff's concerns raised in the RAI and, therefore, is acceptable. The staff's concern described in RAI 2.4.3-2 is resolved.

In RAI 2.4.3-3, dated January 28, 2008, the staff noted that LRA Table 2.4-3 does not include the leak chase channel of the IP3 spent fuel pit as a component subject to an AMR. The staff requested the applicant to include this as a component subject to an AMR or provide a justification for its exclusion.

In its response, dated February 27, 2008, the applicant stated that the leak chase channel is an integral attachment to the liner plate, which is subject to AMR and included in line item "Spent fuel pool liner plate and gate" in LRA Table 2.4-3. The staff agrees with the applicant's position that the leak chase channel, which is welded to the liner plate, can be considered an integral attachment to the liner plate and included as part of the liner plate component. The staff finds the applicant's response adequately addresses the staff's concerns raised in the RAI and, therefore, is acceptable. The staff's concern described in RAI 2.4.3-3 is resolved.

In RAI 2.4.3-4, dated January 28, 2008, the staff noted that, although LRA Table 2.4-3 lists "Crane rails and girders" as a component type subject to an AMR, it is not clear whether this component refers to just crane rails and girders or also refers to the cranes themselves. If it includes the cranes, the applicant was requested to clarify whether all relevant subcomponents ("...including bridge and trolley, rails, and girders") of these in-scope crane systems have been screened in as items requiring an AMR. The staff also requested that the applicant identify the specific cranes in each of these structures that are included within the above component type as within the scope of license renewal and subject to an AMR, and those that are excluded, with technical bases. The applicant also was requested to confirm whether fasteners and rail hardware associated with this component type are within the scope of license renewal and subject to an AMR or provide the technical bases for their exclusion. The staff also requested that the applicant confirm whether there are other hoists and lifting devices that should be included within the scope of license renewal (and subject to an AMR) and, if so, provide their scoping, screening, and AMR results, relevant to the LRA.

In its response, dated February 27, 2008, the applicant stated that the component type "crane rails and girders" in LRA Table 2.4-3 includes bridge and trolley and also refers to the cranes themselves. The applicant further stated that there are no hoists or lifting devices that perform an intended function that would place them in scope and subject to an AMR. The applicant clarified that the specific cranes in scope and subject to an AMR are discussed in LRA Section 2.4-1 for containment buildings and in Section 2.4-3 for turbine building(s) and fuel storage building(s). The applicant confirmed that fasteners and rail hardware are in scope and subject to an AMR. They are, however, considered bulk commodities and are included in LRA Table 2.4-4, line item "structural bolting." Since the language of the line item as currently written could be misleading, in a follow-up RAI, dated May 12, 2008, the staff requested the applicant to correct the line item "crane rails and girders" in LRA Table 2.4-3 to read "cranes, rails and girders."

In its response to the follow-up RAI, dated June 11, 2008, the applicant stated that the line item "crane rails and girders" LRA Table 2.4-3 and LRA Table 3.5.2-3 is corrected to read "cranes, rails and girders". Since the applicant corrected the line item, the staff finds the response acceptable.

In RAI 2.4.3-5, dated January 28, 2008, the staff requested that the applicant confirm whether the component identified as "Structural Steel: beams, columns, plates" in LRA Table 2.4-3 includes bracings, welds, and bolted connections or indicate where they were included. The staff also requested that the applicant include "Battery Racks" (e.g., for emergency diesels), turbine generator pedestals and their structural bearing pads, and diesel generator pedestals and the concrete curb around diesel generator foundations as components subject to an AMR.

In its response, dated February 27, 2008, the applicant clarified that the component identified as "Structural Steel: beams, columns, plates, trusses" in LRA Table 2.4-3 includes bracings and welds associated with the component. The applicant added that bolted connections are addressed in LRA Section 2.4.4 and LRA Table 2.4-4. The applicant further clarified that battery racks (e.g., for emergency diesel) are within the scope of license renewal and subject to an AMR and are included as bulk commodities within line item "component and piping support" in LRA Table 2.4-4. The applicant further clarified that the turbine generator pedestals, diesel generator pedestals, and the concrete curb around diesel generator foundations are included within the LRA Table 2.4-3 as part of line item "Floor slabs, interior walls and ceiling" and line item "Foundations." The applicant stated that structural bearing pads associated with the turbine generator pedestal are not within the scope of license renewal because they are not safety-related and not required to demonstrate compliance with 10 CFR 54.4(a)(3). Failure of the bearing pads will not prevent satisfactory accomplishment of a safety function. Based on this response, the staff finds that the applicant has adequately clarified the inclusion or justified the exclusion, as applicable, of each of the structural components noted in the RAI. The staff finds the applicant's response adequately addresses the staff's concerns raised in the RAI and, therefore, is acceptable. The staff's concern described in RAI 2.4.3-5 is resolved.

2.4.3.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI and follow-up RAI responses to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine if the applicant failed to identify any SCs subject to an AMR. Again, the staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the turbine buildings, auxiliary buildings, and other structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4 Bulk Commodities

2.4.4.1 Summary of Technical Information in the Application

LRA Section 2.4.4 describes bulk commodities, the structural components or commodities that perform or support intended functions of in-scope SSCs. Bulk commodities unique to a specific structure are included in the review for that structure (LRA Sections 2.4.1 through 2.4.3). Bulk commodities common to Indian Point in-scope SSCs (*e.g.*, anchors (including rock bolts), embedments, pipe and equipment supports, instrument panels and racks, cable trays, and conduits) are addressed in this section.

Insulation may have the specific intended functions of (1) controlling the heat load during DBAs in areas with safety-related equipment, (insulation and Insulation jacket) or (2) maintaining integrity such that falling insulation does not damage safety-related equipment (reflective metallic-type reactor vessel insulation).

Bulk commodities have the following intended functions for 10 CFR 54.4(a)(1), (a)(2), and (a)(3): Provide support, shelter, and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal.

LRA Table 2.4-4 identifies bulk commodities' component types, grouped by material (steel/other metals, concrete, other materials), within the scope of license renewal and subject to an AMR as well as their intended functions.

2.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.4.4, the staff 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 LRA Section 2.4.4 and LRA Table 2.4-4, the applicant discussed and listed the structural bulk commodities components common to in-scope structures that are subject to an AMR. Because of a lack of clarity in LRA Table 2.4-4, in RAI 2.4.4-1, dated January 28, 2008, the staff requested that the applicant confirm or clarify and appropriately address whether the following bulk commodities have been screened in as components subject to an AMR, in LRA Table 2.4-4:

(i) expansion anchors
(ii) vibration isolation elements
(iii) flood curbs
(iv) waterproofing membrane
(v) sliding support bearings and sliding support surfaces

The applicant also was requested to explicitly state the specific materials that are classified as "Other Materials" in LRA Table 2.4-4.

In its response, dated February 27, 2008, the applicant clarified the screening of each component identified in the RAI as follows:

(i) Expansion Anchors are addressed in LRA Table 2.4-4 under line item "anchorages/embedments."

(ii) There are no vibration isolation elements identified as within the scope of license renewal and subject to AMR.

(iii) Flood curbs are included in the review of structures. Considered integral to floor slabs, they are included in the review for those line items identified in LRA Tables 2.4-1 as "beams, columns, interior walls, slabs," Table 2.4-2 as "beams, columns, floor slabs and walls" and Table 2.4-3 as "floor slabs, interior walls, ceilings."

(iv) Waterproofing membranes are not in-scope. Waterproofing membranes are not safety-related and are not required to demonstrate compliance with 10 CFR 54.4(a)(3). Failure of these membranes will not prevent satisfactory accomplishment of a safety function.

(v) The sliding support bearings and sliding support surfaces identified as within the scope of license renewal are documented in LRA Table 2.4-1, line item "Lubrite sliding surfaces."

The applicant also stated that materials classified as "Other Materials" in LRA Table 2.4-4 are those materials that were not captured by what is considered basic structural materials (i.e., steel or concrete) and that the material make-up of these commodities is specifically identified in LRA Section 3.5.2.1.4.

The staff finds that the applicant adequately clarified the issues related to the screening of the five specific structural components identified in the RAI. The staff also verified that, in LRA

Section 3.5.2.1.4, the applicant identified the bulk commodity component materials that make up the line item "Other Materials." These other materials, identified in LRA Section 3.5.2.1.4 are aluminum, cera blanket, cerafiber, elastomer, fiberglass and/or calcium silicate, mineral wool, and pyrocrete. The staff finds that the applicant's response adequately addresses the staff's concerns raised in the RAI and, therefore, is acceptable. The staff's concern described in RAI 2.4.4-1 is resolved.

In RAI 2.4.4-2, dated January 28, 2008, with regard to the components "insulation" and "insulation jacket" identified in LRA Table 2.4-4, the staff pointed out that it was unclear as to which insulation (and material) and insulation jacket within the scope of license renewal were included in these items. The applicant was requested to clarify whether the insulation and jacketing on the containment liner, reactor vessel, RCS, MS and FW systems are included.

The applicant also was requested to provide the following information with regard to insulation that is used to control the maximum temperature of safety-related structural elements:

(a) Identify the structures and structural components designated as within the scope of license renewal that have insulation and/or insulation jacketing, and identify their location in the plant. Identify locations of the thermal insulation that serve an intended function in accordance with 10 CFR 54.4(a)(2) and describe the scoping and screening results of thermal insulation, and provide the technical basis for its exclusion from the scope of license renewal.

(b) For insulation and insulation jacketing materials associated with item (a) above that do not require aging management, submit the technical basis for this conclusion, including plant-specific operating experience.

(c) For insulation and insulation jacketing materials associated with item (a) above that require aging management, indicate the applicable LRA sections that identify the AMP(s) credited to manage their aging.

In its response, dated February 27, 2008, the applicant addressed each of the items in the RAI as follows:

(a) The applicant stated that structures and structural components within the scope of license renewal that have insulation and/or insulation jacketing that serves an intended function pursuant to 10 CFR 54.4(a)(2) are the containment liner and high-temperature piping at containment piping penetrations. The applicant stated that the containment liner insulation is listed in LRA Table 2.4-1, and the insulation associated with hot containment penetrations is addressed in LRA Section 2.4.4 and in LRA Table 2.4-4.

(b) The applicant clarified that insulation and insulation jacketing materials associated with item (a) do not require an AMP because these insulation materials are exposed to indoor air environment and the containment liner insulation is encapsulated in a stainless steel jacket and is not subject to external environments. The applicant further stated that, in these environments, these materials have no aging effects requiring management. The operating experience review specifically considered plant-specific information related to the effects of aging on insulation materials, and that review confirmed that no aging effects requiring management are applicable to the insulation materials that are subject to an AMR at IP2 and IP3.

(c) The applicant stated that aging management review results for insulation and insulation jacketing materials are shown in LRA Tables 3.5.2-1 and 3.5.2-4.

The applicant reiterated that, since there are no aging effects requiring management for insulation, no AMP is credited, noting that insulation materials in an indoor air environment are not susceptible to degradation from the effects of aging.

In its response, and in the context of insulation that serves to limit the temperature of safety-related structural components, the applicant confirmed that the structures and structural components, within the scope of license renewal and subject to an AMR, that have insulation and/or insulation jacketing are the containment liner and high-temperature piping at the containment penetrations. The applicant concluded that none of the in-scope insulating material used at IP2 and IP3 requires any management for aging effects because of its favorable operating experience and the fact that it is only exposed to an indoor air environment and encapsulated in metallic jacketing. The staff finds that this conclusion is consistent with the GALL Report, Volume II. The staff further finds that the applicant's response to RAI 2.4.4-2 adequately addressed the staff's question with regard to insulation and, therefore, is acceptable. The staff's concern described in RAI 2.4.4-2 is resolved.

2.4.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine whether the applicant failed to identify any SCs subject to an AMR. The staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the bulk commodities SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical and Instrumentation and Control Systems

This section documents the staff's review of the applicant's scoping and screening results for electrical and I&C systems.

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SCs within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus 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.

The staff's evaluation of the information in the LRA sought to determine whether the applicant had identified, in accordance with 10 CFR 54.4, components and supporting structures for electrical and I&C systems that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections, focusing 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 electrical and I&C system to determine whether the applicant had omitted from the scope of license renewal components with license renewal intended functions in accordance with 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all license renewal intended functions in accordance with 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether (1) the functions are performed with moving parts or a change in configuration or properties, or (2) the SCs are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.5.1 Electrical and Instrumentation and Control Systems

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and instrumentation and control systems. As stated in LRA Section 2.1.1, plant electrical and instrument and control (I&C) systems are included in the scope of license renewal as are electrical and I&C components in mechanical systems. The default inclusion of plant electrical and I&C systems in the scope of license renewal reflects the method for the integrated plant assessment (IPA) of electrical systems. This method is different from the methods used for mechanical systems and structures.

The applicant stated that the basic philosophy of the electrical and I&C components IPA is that components are included in the review unless specifically screened out. In the plant spaces approach, this method eliminates the need for unique identification of every component and its specific location so components are not excluded improperly from an AMR. The electrical and I&C IPA began by grouping all components into commodity groups of similar electrical and I&C components with common characteristics and by determining component level intended functions of the commodity groups.

The IPA eliminated commodity groups and specific plant systems from further review as the intended functions of commodity groups were examined. In addition to the plant electrical systems, certain switchyard components required to restore offsite power following SBO were included conservatively within the scope of license renewal even though those components are not relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for SBO (10 CFR 50.63).

The applicant further stated that the offsite power system provides the electrical interconnection between IPEC and the offsite transmission network. The offsite power sources required to support SBO recovery actions supply the station auxiliary transformers. Specifically, the offsite power recovery path includes the station auxiliary transformers, the 138 kV and 13.8 kV switchyard circuit breakers supplying the station auxiliary transformers, the circuit breaker-to-transformer and transformer-to-onsite electrical distribution interconnections, control circuits, and structures.

The electrical and instrumentation and control systems perform functions that support SBO and EQ.

LRA Table 2.5-1 identifies electrical and instrumentation and control systems component types within the scope of license renewal and subject to an AMR:

- cable connections (metallic parts)
- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
- electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits
- electrical connections not subject to 10 CFR 50.49 EQ requirements exposed to borated water leakage
- fuse holders (insulation material)
- high-voltage insulators for SBO recovery
- inaccessible medium-voltage (2kV to 35kV) cables not subject to 10 CFR 50.49 EQ requirements
- metal-enclosed bus (non-segregated) and connections for SBO recovery
- metal-enclosed bus (non-segregated), insulation/insulators for SBO recovery
- metal-enclosed bus (non-segregated) enclosure assemblies for SBO recovery
- switchyard bus and connections for SBO recovery
- transmission conductors and connections for SBO recovery
- 138 kV direct burial insulated transmission cables

The intended functions of the electrical and instrumentation and control systems component types within the scope of license renewal include the following functions:

- connect specified electrical circuit portions to deliver voltage, current, or signals
- insulate and support electrical conductors
- structurally or functionally support equipment required for the 10 CFR 54.4(a)(3) regulated events

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5 and the UFSAR using the evaluation methodology described in SER Section 2.5 and the guidance in SRP-LR Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems."

During its review, the staff evaluated the system functions described in the LRA and UFSAR 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 within the scope of license renewal to verify that the applicant had not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.5, the staff identified several 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.

The staff noted that, according to LRA Section 2.5, two independent paths from the safety-related buses to the first circuit breaker from the offsite transmission line were not included within the scope of license renewal. General Design Criterion 17 of 10 CFR Part 50, Appendix A, requires that electric power from the transmission network to the onsite electric distribution system be supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. In addition, the staff noted that the guidance provided by letter dated April 1, 2002, "Staff Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," and later incorporated in SRP-LR Section 2.5.2.1.1, states:

> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical system, and the associated control circuits and structures. Ensuring that the appropriate offsite power system long-lived passive SCs that are part of this circuit path are subject to an AMR will assure that the bases underlying the SBO requirements are maintained over the period of extended license.

According to this guidance, the NRC staff position is that, for the purposes of license renewal, the specified offsite power recovery path elements should be included in the scope of license renewal. In RAI 2.5-1, dated October 24, 2007, the staff conveyed its position that both paths from the safety-related 480 V buses to the first circuit breaker from the offsite line used to control the offsite circuits to the plant should be included within the scope of license renewal. Therefore, the staff requested that the applicant provide a detailed explanation of which high voltage breakers and other components in the switchyard will be connected from the startup transformers up to the offsite power system for the purpose of SBO recovery.

In its response, dated November 16, 2007, the applicant stated that the Buchanan substation, which includes the 345 kV, 138 kV, and 13.8 kV sections, provides for the interconnection of multiple sources of power and constitutes the offsite power source for IP2 and IP3.

In the LRA, Figure 2.5-2, "IP2 Offsite Power Scoping Diagram," shows the IP2 primary offsite power source, the 6.9 kV source from the station auxiliary transformer which is connected to the 138 kV Buchanan substation through circuit breaker F2. The applicant's November 16, 2007 response revised the scoping boundary for both offsite power sources for IP2. First, the station auxiliary transformer is connected to the 138 kV Buchanan substation via switchyard bus, overhead transmission conductors, and underground transmission conductors through motor-operated disconnect F3A (primary path). The staff determined that this change to a motor-operated disconnect is not consistent with the staff guidance and, therefore, is unacceptable. Secondly, the November 16, 2007 response delineated the secondary offsite power source (alternate path). The gas turbine (GT) autotransformer is connected to the 13.8 kV Buchanan substation via underground medium voltage cable through 13.8 kV circuit breaker F2-3.

LRA Figure 2.5-3, "IP3 Offsite Power Scoping Diagram," was modified in the applicant's November 16, 2007, response to add the secondary offsite power feeder, indicating that the 6.9 kV buses receive power from two independent sources: the 138 kV/6.9 kV station auxiliary transformer and the 13.8 kV/6.9 kV GT autotransformer. The station auxiliary transformer is connected to the 138 kV Buchanan substation via switchyard bus and overhead transmission conductors through circuit breaker BT2-6, and the GT autotransformer is connected to the 13.8 kV Buchanan substation via underground medium voltage cable through 13.8 kV circuit breaker F3-1.

During a telephone conference, documented in a conference call summary dated December 4, 2007, the staff requested that Entergy explain its response to RAI 2.5-1 with regard to why the connection point for offsite power (for the purpose of station blackout recovery) changed from circuit breaker F2 to a motor-operated disconnect for IP2. The staff informed the applicant that this change is not consistent with the staff's guidance and, therefore, is unacceptable.

In a letter dated March 24, 2008, the applicant modified its scoping boundary for the primary offsite power path for IP2, as shown in modified Figure 2.5-2, "IP2 Offsite Power Scoping Diagram." The station auxiliary transformer is connected to the 138 kV Buchanan substation via switchyard bus, overhead transmission conductors, and underground transmission conductors through switchyard breakers F2 and BT 3-4. The change from motor-operated disconnects to 138 kV circuit breakers addresses the staff's concern for the scoping boundary for the primary offsite power path and provides closure for Open Item 2.5-1.

By letter dated May 20, 2009, the staff requested that the applicant explain why the secondary offsite circuit (the delayed access circuit) path, from the first inter-tie with the offsite distribution systems at the Buchanan substations to the safety buses, was not included in the scope of license renewal.

By letter dated June 12, 2009, the applicant stated that the components up to and including either the 138 kV circuit breaker F1 or 345 kV circuit breaker F7 for IP2, and either the 138 kV circuit breaker F3 or 345 kV circuit breaker F7 for IP3 were not included in the scope of license renewal because they do not meet the scoping criteria specified in 10 CFR 54.4. The staff finds the response acceptable as it is in accordance with the IP2 and IP3 current licensing basis and applicable regulatory requirements. This closes Open Item 2.5-1.

The applicant did not specifically exclude the associated control circuits and structures for the circuit breakers and thus, it was unclear if these components are included in the scope of license renewal. In RAI 2.5-5, the staff requested that the applicant confirm whether the associated control cables and structures for the circuit breakers have been included in the scope of license renewal. In letter dated August 14, 2008, the applicant clarified its response to RAI 2.5-1 and confirmed that the associated control cables and structures for the circuit breakers have been included in the scope of license renewal. Therefore, the staff finds the response acceptable.

In RAI 2.5-2, dated October 24, 2007, the staff requested the applicant to clarify why elements such as resistance temperature detectors (RTDs), sensors, thermocouples, and transducers are not included in the list of components and/or commodity groups subject to an AMR if a pressure boundary is applicable. In its response, dated November 16, 2007, the applicant stated that RTDs, sensors, thermocouples, and transducers associated with the pressure boundary are evaluated in mechanical systems. Examples are thermowells and flow elements. LRA Section 2.1.2.3.1 states that the pressure boundary function that may be associated with some electrical and I&C components was considered in the mechanical aging management reviews. The staff verified through a sampling of mechanical systems that the applicant had scoped and screened the passive mechanical components (e.g., thermowells and flow elements) associated with the electrical elements in question. Therefore, the staff finds the response acceptable.

In RAI 2.5-3, dated October 24, 2007, the staff requested clarification as to why Section 2.5 of the LRA did not include splices, terminal blocks, control cables, and isolated-phase bus in the commodity group of "cables & connections, bus, electrical portions of electrical and I&C penetration assemblies." In its response, dated November 16, 2007, the applicant stated that electrical splices, terminal blocks, and control cables were included in the commodity group "electrical cables and connections not subject to 10 CFR 50.49 EQ requirements." Thus, these components are subject to an aging management review. The isolated-phase bus is not subject to an AMR because it does not perform an intended function. Since the applicant clarified that the electrical splices, terminal blocks, and control cables are subject to an AMR, the staff finds the response acceptable.

2.5.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SSCs within the scope of license renewal. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the electrical and I&C component commodity groups components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6 Conclusion for Scoping and Screening

The staff reviewed the information in LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results" and determines that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), except as noted above. Accordingly, the staff concludes that the applicant has adequately identified those systems and components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

With regard to these matters, the staff concludes that reasonable assurance exists that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

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11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff. By letter dated April 23, 2007, and as supplemented by letters dated May 3 and June 21, 2007, Entergy Nuclear Operations, Inc. (Entergy or the applicant), submitted the LRA in accordance with Title 10, Part 54, of the Code of Federal Regulations. Entergy requests renewal of the IP2 and IP3 operating licenses for a period of 20 years beyond the current expirations at midnight on September 28, 2013, for IP2, and at midnight on December 12, 2015, for IP3.

Indian Point is located approximately 24 miles north of the New York City boundary line. The NRC issued operating licenses on September 28, 1973, for IP2, and on December 12, 1975, for IP3. IP2 and IP3 employ a pressurized water reactor design with a dry ambient containment. Westinghouse Electric Corporation supplied the nuclear steam supply system. The licensed output of each unit is 3216 megawatts thermal with a gross electrical output of approximately 1080 megawatts electric.

On January 15, 2009, the staff issued an SER with open items, in which it identified 20 open items necessitating further review. This SER presents the staff's review of information submitted through August 6, 2009. The staff resolved the 20 open items before it made its final determination on the LRA.

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Safety Evaluation Report

Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3

Docket Nos. 50-247 and 50-286

Entergy Nuclear Operations, Inc.

Office of Nuclear Reactor Regulation

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NUREG-1930, Vol. 2

Safety Evaluation Report

Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3

Docket Nos. 50-247 and 50-286

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated April 23, 2007, and as supplemented by letters dated May 3 and June 21, 2007, Entergy Nuclear Operations, Inc., (Entergy or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the *Code of Federal Regulations*, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Entergy requests renewal of the IP2 and IP3 operating licenses (Facility Operating License Numbers DPR-26 and DPR-64, respectively) for a period of 20 years beyond the current expirations at midnight on September 28, 2013, for IP2, and at midnight on December 12, 2015, for IP3.

Indian Point is located approximately 24 miles north of the New York City boundary line. The NRC issued the construction permits on October 14, 1966, for IP2, and on August 13, 1969, for IP3. The NRC issued the operating licenses on September 28, 1973, for IP2, and on December 12, 1975, for IP3. IP2 and IP3 employ a pressurized water reactor design with a dry ambient containment. Westinghouse Electric Corporation supplied the nuclear steam supply system and Westinghouse Development Corporation originally designed and constructed the balance of the plant with the assistance of its agent, United Engineers and Constructors. The licensed power output of each unit is 3216 megawatts thermal (MWt) with a gross electrical output of approximately 1080 megawatts electric (MWe).

On January 15, 2009, the staff issued an SER with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, in which the staff identified 20 open items necessitating further review. This SER presents the status of the staff's review of information submitted through August 6, 2009, the cutoff date for consideration in this SER. The 20 open items that had been identified in the previous SER were resolved before the staff made a final determination on the LRA. SER Section 1.5 summarizes these items and their resolution. Section 6.0 provides the staff's final conclusion on its review of the IP2 and IP3 LRA.

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Appendices

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ABBREVIATIONS

AC	alternating current
ACAR	aluminum conductor aluminum-reinforced
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum core steel-reinforced
ADAMS	Agencywide Document Access and Management System
ADV	atmospheric dump valve
AEIC	Association of Edison Illuminating Companies
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
AMSAC	ATWS Mitigating System Actuation Circuitry
ANSI	American National Standards Institute
APCSB	Auxiliary and Power Conversion Systems Branch
ART	adjusted reference temperature
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
B&PV	Boiler and Pressure Vessel
BADGER	boron-10 areal density gauge for evaluating racks
BIL	basic impulse level
BMI	bottom mounted instrumentation
BOP	balance of plant
BTP	branch technical position
BVS	building vent sampling
BWR	boiling water reactor
C	Celsius
CASS	cast austenitic stainless steel
CB	core barrel
CCW	component cooling water
CEA	control element assembly
CETNA™	core exit thermocouple nozzle assembly
CFR	*Code of Federal Regulations*
CII	containment inservice inspection
CL	chlorination system
CLB	current licensing basis
CO_2	carbon dioxide
CR	condition report

CRD	control rod drive
CRDM	control rod drive mechanism
Cr-Mo	chromium-molybdenum
CS	containment spray
CST	condensate storage tank
Cu	copper
CUF	cumulative usage factor
CVCS	chemical and volume control
C_VUSE	Charpy upper-shelf energy
CW	circulating water
CWM	IP3 city water system code
CYW	IP2 city water system code
DBA	design basis accident
DBD	design basis document
DBE	design basis event
DC	direct current
ECCS	emergency core cooling system
ECT	eddy current testing
EDG	emergency diesel generator
EFPY	effective full-power year
EMA	equivalent margin analysis
EN	shelter or protection
EPRI	Electric Power Research Institute
EQ	environmental qualification, environmentally qualified
EQAP	Entergy Quality Assurance Program
ER	Environmental Report (Applicant's Environmental Report Operating License Renewal Stage)
ESF	engineered safety features
F	Fahrenheit
FAC	flow accelerated corrosion
F_{en}	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission
FLB	flood barrier
FLT	filtration
FMP	Fatigue Monitoring Program
FR	*Federal Register*
FRV	feedwater regulating valve
FSAR	final safety analysis report
ft-lb	foot-pound
FW	feedwater
FWST	fire water storage tank
GALL	Generic Aging Lessons Learned Report
GDC	general design criteria or general design criterion
GEIS	Generic Environmental Impact Statement
GL	generic letter

GSI	generic safety issue
GT	gas turbine
H_2	hydrogen
HELB	high-energy line break
HEPA	high efficiency particulate air
HPSI	high pressure safety injection
HVAC	heating, ventilation, and air conditioning
HX	heat exchanger
I&C	instrumentation and controls
IA	instrument air
IASCC	irradiation assisted stress corrosion cracking
IEEE	Institute of Electrical and Electronics Engineers
IGA	intergranular attack
IGSCC	inter-granular stress corrosion cracking
ILRT	integrated leak rate testing
IN	information notice
INPO	Institute of Nuclear Power Operations
IP1	Indian Point Nuclear Generating Unit 1
IP2	Indian Point Nuclear Generating Unit 2
IP3	Indian Point Nuclear Generating Unit 3
IP	Indian Point (site)
IPA	integrated plant assessment
IPEC	Indian Point Energy Center
ISG	interim staff guidance
ISI	inservice inspection
ISO	International Standards Organization
ksi	kip per square inch
KV or kV	kilo-volt
lb	pound
LBB	leak before break
LO	lube oil
LOCA	loss of coolant accident
LRA	license renewal application
µmhos/cm	micromhos per centimeter
MB	missile barrier
MC	ASME Class for metal containment components
MEB	metal-enclosed bus
MFW	main feedwater
MIC	microbiologically influenced corrosion
MOV	motor-operated valve
MPa	megapascal
MRP	Materials Reliability Program
MS	main steam
MSIV	main steam isolation valve

MWe	megawatts-electric
MWt	megawatts-thermal
n/cm^2	neutrons per square centimeter
NaOH	sodium hydroxide
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NESC	National Electric Safety Code
NFPA	National Fire Protection Association
Ni	nickel
NPS	nominal pipe size
NRC	US Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSAS	nonsafety system affecting safety system
NSSS	nuclear steam supply system
NYPA	New York Power Authority
O_2	oxygen
ODSCC	outside-diameter stress corrosion cracking
OI	open item
P&ID	piping and instrumentation diagram
PAB	primary auxiliary building
PB	pressure boundary
PBD	program basis document
pH	potential of hydrogen
PM	preventive maintenance
PORV	power-operated relief valve
ppb	parts per billion
ppm	parts per million
psi	pound per square inch
psig	pound-force per square inch gauge
PSPM	periodic surveillance and preventive maintenance
P-T	pressure-temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PW	primary water makeup
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
RAI	request for additional information
RCCA	rod cluster control assembly
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide

RHR	residual heat removal
RI-ISI	risk-informed inservice inspection
RO	refueling outage
RPV	reactor pressure vessel
RT_{NDT}	reference temperature nil ductility transition
RT_{PTS}	reference temperature for pressurized thermal shock
RTD	resistance temperature detector
RVCH	reactor vessel closure head
RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RVLIS	reactor vessel level indication system
RW	river water
RWST	refueling water storage tank
S&PC	steam and power conversion
S_A	stress allowables
SAR	safety analysis report
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SER	safety evaluation report
SFP	spent fuel pool
SFPC	spent fuel pit/pool cooling
SG	steam generator
SGBD	steam generator blowdown
SI	safety injection
SMP	structures monitoring program
SO_2	sulfur dioxide
SOC	statement of consideration
SOV	solenoid-operated valve
SPU	stretch power uprate
SR	surveillance requirement
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SS	stainless steel
SSC	system, structure, and component
SSE	safe-shutdown earthquake
SSFS	safety system function sheets
SW	service water
TLAA	time-limited aging analysis
TS	technical specification(s)
TSC	technical support center
UFSAR	Updated Final Safety Analysis Report
USE	upper-shelf energy
UT	ultrasonic testing
UV	ultraviolet

V	volt
VCT	volume control tank
WCAP	Westinghouse Commercial Atomic Power
WOG	Westinghouse Owners Group
XLPE	cross-linked polyethylene
yr	year
Zn	zinc
1/4 T	one-fourth of the way through the vessel wall measured from the internal surface of the vessel

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff). In license renewal application (LRA), Appendix B, Entergy Nuclear Operations, Inc. (Entergy or the applicant) described the 41 AMPs that it relies on to manage or monitor the aging of passive, long-lived structures and components (SCs).

In LRA Section 3, the applicant provided the results of the AMRs for those SCs identified in LRA Section 2 as 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 its LRA, the applicant referenced NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report" (the GALL Report), dated September 2005. 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 period of extended 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 license renewal structures and components (SCs). 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 its programs correspond to those reviewed and approved in the report.

The purpose of the GALL Report is to provide a summary of staff-approved AMPs to manage or monitor the aging of SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review will be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a quick reference for applicants and staff reviewers to AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report is split into two volumes. Volume 1 summarizes the aging management reviews that are discussed in Volume 2. Volume 2 lists generic aging management reviews (AMRs) of SSC that may be in the scope of License Renewal Applications (LRAs) and identifies GALL AMPs that are acceptable to manage the listed aging effects. Revision 1 of the GALL Report incorporates changes based on experience gained from numerous NRC staff reviews of LRAs and other insights identified by stakeholders.

The GALL Report identifies: (1) systems, structures, and components (SSCs), (2) SC materials, (3) environments to which the SCs are exposed, (4) the aging effects of the materials and environments, (5) the AMPs credited with managing or monitoring the aging effects, and (6) recommendations for further applicant evaluations of aging management for certain component types.

NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated September 2005, was prepared based on both the GALL Report model and lessons learned from the demonstration project.

If an LRA references the GALL Report as the approach used to manage aging effects, the NRC staff will use the GALL Report as a basis for the LRA assessment consistent with guidance specified in the SRP-LR.

The staff's review was in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and the guidance of the SRP-LR and the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMPs and AMRs, during the weeks of August 26, 2007 and October 22, 2007, November 27 - 29, 2007, and February 19 – 22, 2008. The onsite audits and reviews are designed for maximum efficiency of the staff's LRA review. The applicant can respond to questions, the staff can readily evaluate the applicant's responses, the need for formal correspondence between the staff and the applicant is reduced, and the result is an improvement in review efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format. This standard format was agreed to by the staff and the Nuclear Energy Institute (NEI) in a letter dated April 7, 2003. The revised LRA format incorporates lessons learned from the staff's reviews of the previous five LRAs, which used a format developed from information gained during a staff-NEI demonstration project conducted to evaluate the use of the GALL Report in the LRA review process.

The organization of LRA Section 3 parallels that of SRP-LR Chapter 3. LRA Section 3 presents AMR results information in the following two table types:

(1) Table 1's: 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 table type is the first in LRA Section 3.

(2) Table 2's: 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 table type is the second in LRA Section 3, and "y" indicates the system table number.

The content of the previous LRAs and of the Entergy application is essentially the same. The intent of the revised format of the Entergy LRA was to modify the tables in LRA Section 3 to provide additional information that would assist in the staff's review. In its Table 1's, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In its Table 2's, the applicant identified the linkage between the scoping and screening results in LRA Section 2 and the AMRs in LRA Section 3.

3.0.1.1 Overview of Table 1's

Each Table 1 compares in summary, how the facility aligns with the corresponding tables in the GALL Report. The tables are essentially the same as Tables 1 through 6 in the GALL Report, 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 is a means for the staff reviewer to cross-reference Table 2's with Table 1's. In the "Discussion" column the applicant provided clarifying information. The following are examples of information that might be contained within this column:

- further evaluation recommended - information or reference to where that information is located
- the name of a plant-specific program
- exceptions to GALL Report assumptions
- discussion of how the line is consistent with the corresponding line item in the GALL Report when the consistency may not be obvious
- discussion of how the item is different from the corresponding line item in the GALL Report (e.g., when an exception is taken to a GALL Report AMP)

The format of each Table 1 allows the staff to align a specific row in the table with the corresponding GALL Report table row so that the consistency can be checked easily.

3.0.1.2 Overview of Table 2's

Each Table 2 provides the detailed results of the AMRs for components identified in LRA Section 2 as subject to an AMR. The LRA has a Table 2 for each of the systems or structures within a specific system grouping (e.g., reactor coolant system (RCS), engineered safety features (ESF), auxiliary systems, etc.). For example, the ESF group has tables specific to the containment spray (CS) system, containment isolation (CI) system, and emergency core cooling system (ECCS). Each Table 2 consists of nine columns:

- Component Type – The first column lists LRA Section 2 component types subject to an AMR in alphabetical order.
- Intended Function – The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.0-1.
- Material – The third column lists the particular construction material(s) for the component type.
- Environment – The fourth column lists the environments to which the component types are exposed. Internal and external service environments are indicated with a list of these environments in LRA Tables 3.0-1, 3.0-2, and 3.0-3.
- Aging Effect Requiring Management – The fifth column lists aging effects requiring management (AERMs). As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.

- Aging Management Programs – The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.
- NUREG-1801 Vol. 2 Item – The seventh column lists the GALL Report item(s) identified in the LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there are no corresponding items in the GALL Report, the applicant leaves the column blank in order to identify the AMR results in the LRA tables corresponding to the items in the GALL Report tables.
- Table 1 Item – The eighth column lists the corresponding summary item number from LRA Table 1. If the applicant identifies in each LRA Table 2 AMR results consistent with the GALL Report, the Table 1 line item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, column eight is left blank. In this manner, the information from the two tables can be correlated.
- Notes – The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI work group and will be used in future LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

The staff conducted three types of evaluations of the AMRs and AMPs:

(1) For items that the applicant stated as consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency.

(2) For items that the applicant stated as consistent with the GALL Report with exceptions, enhancements, or both, the staff conducted either an audit or a technical review of the item to determine consistency. In addition, the staff conducted either an audit or a technical review of the applicant's technical justifications for the exceptions or the adequacy of the enhancements.

The SRP-LR states that an applicant may take one or more exceptions to specific GALL AMP elements. However, any deviation from or exception to the GALL AMP should be described and justified.

In some cases, an applicant may choose an existing plant program that does not meet all of the ten program elements defined in the GALL AMP. However, the applicant may make a commitment to augment the existing program to satisfy the GALL AMP prior to the period of extended operation. Enhancements include, but are not limited to, activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

(3) For other items, the staff conducted a technical review to verify compliance with 10 CFR 54.21(a)(3).

Staff audits and technical reviews of the applicant's AMPs and AMRs determine whether the effects of aging on SCs will be adequately managed so that the intended function will be maintained consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR Part 54.21.

3.0.2.1 Review of Programs

For programs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify the claim. For each program with one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the modified program would adequately manage the aging effect(s) for which it was credited. For programs not evaluated in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the programs against the following 10 program elements defined in SRP-LR Appendix A.

(1) Scope of the Program – Scope of the program should include the specific SCs 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 function(s).

(4) Detection of Aging Effects – Detection of aging effects should occur before there is a loss of structure or component intended function(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 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 functions 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 for 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 adequately managed so that the SC intended functions will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) are documented in SER Section 3.0.3.

The staff reviewed the applicant's quality assurance (QA) program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the QA program included assessment of program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls.

The staff reviewed the information on program element (10) "operating experience," and documented its evaluation in SER Section 3.0.3.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether or not the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column seven of the LRA, "NUREG-1801 Vol. 2 Item," correlate to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to verify these correlations. A blank in column seven indicates that the applicant was unable to identify an appropriate correlation in the GALL Report. The staff also conducted a technical review of combinations not consistent with the GALL Report. The next column, "Table 1 Item," refers to a number indicating the correlating row in Table 1.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and AMPs that it reviewed, the staff also reviewed the UFSAR supplement, which summarizes the applicant's programs and activities for managing aging effects for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In its review, the staff used the LRA, LRA supplements, the SRP-LR, and the GALL Report.

During the onsite audits, the staff also examined the applicant's justifications to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. 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. The staff's audit activities are documented in the Audit Report (ADAMS Accession No. ML083540662).

3.0.3 Aging Management Programs

SER Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the systems or structures that credit the AMPs and the GALL AMP with which the applicant claimed consistency and shows the section of this SER in which the staff's evaluation of the program is documented.

Table 3.0.3-1 IP2 and IP3 Aging Management Programs

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Aboveground Steel Tanks Program (B.1.1)	Existing	Consistent with enhancements	XI.M29	auxiliary systems / steam and power conversion systems	3.0.3.2.1
Bolting Integrity Program (B.1.2)	Existing	Consistent with enhancement	XI.M18	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.2
Boraflex Monitoring Program (B.1.3)	Existing	Consistent with exceptions	XI.M22	auxiliary systems	3.0.3.2.3
Boral Surveillance Program (B.1.4)	Existing	Plant-specific		auxiliary systems	3.0.3.3.1
Boric Acid Corrosion Prevention Program (B.1.5)	Existing	Consistent	XI.M10	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / structures and component supports / electrical and instrumentation and controls	3.0.3.1.1
Buried Piping and Tanks Inspection Program (B.1.6)	New	Consistent	XI.M34	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.2
Containment Leak Rate Program (B.1.7)	Existing	Consistent	XI.S4	structures and component supports	3.0.3.1.3
Containment Inservice Inspection Program (B.1.8)	Existing	Plant-specific		structures and component supports	3.0.3.3.2
Diesel Fuel Monitoring Program (B.1.9)	Existing	Consistent with exceptions and enhancements	XI.M30	auxiliary systems	3.0.3.2.4
Environmental Qualification of Electric Components Program (B.1.10)	Existing	Consistent	X.E1	electrical and instrumentation and controls	3.0.3.1.4

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
External Surfaces Monitoring Program (B.1.11)	Existing	Consistent with enhancement	XI.M36	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.5
Fatigue Monitoring Program (B.1.12)	Existing	Consistent with exception and enhancement	X.M1	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.6
Fire Protection Program (B.1.13)	Existing	Consistent with exception and enhancements	XI.M26	auxiliary systems / structures and component supports	3.0.3.2.7
Fire Water System Program (B.1.14)	Existing	Consistent with exception and enhancements	XI.M27	auxiliary systems / structures and component supports	3.0.3.2.8
Flow-Accelerated Corrosion Program (B.1.15)	Existing	Consistent with exception	XI.M17	auxiliary systems / steam and power conversion systems	3.0.3.1.5
Flux Thimble Tube Inspection Program (B.1.16)	Existing	Consistent with enhancements	XI.M37	reactor vessel, internals and reactor coolant system	3.0.3.2.9
Heat Exchanger Monitoring Program (B.1.17)	Existing	Plant-specific		engineered safety features systems / auxiliary systems	3.0.3.3.3
Inservice Inspection Program (B.1.18)	Existing	Plant-specific		reactor vessel, internals and reactor coolant system / structures and component supports	3.0.3.3.4
Masonry Wall Program (B.1.19)	Existing	Consistent with enhancement	XI.S5	structures and component supports	3.0.3.2.10
Metal-Enclosed Bus Inspection Program (B.1.20)	Existing	Consistent with exceptions and enhancements	XI.E4	electrical and instrumentation and controls	3.0.3.2.11
Nickel Alloy Inspection Program (B.1.21)	Existing	Plant-specific		reactor vessel, internals and reactor coolant system	3.0.3.3.5
Non-EQ Bolted Cable Connections Program (B.1.22)	New	Plant-specific		electrical and instrumentation and controls	3.0.3.3.6

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Non-EQ Inaccessible Medium-Voltage Cable Program (B.1.23)	New	Consistent	XI.E3	electrical and instrumentation and controls	3.0.3.1.6
Non-EQ Instrumentation Circuits Test Review Program (B.1.24)	New	Consistent	XI.E2	electrical and instrumentation and controls	3.0.3.1.7
Non-EQ Insulated Cables and Connections Program (B.1.25)	New	Consistent	XI.E1	electrical and instrumentation and controls	3.0.3.1.8
Oil Analysis Program (B.1.26)	Existing	Consistent with exception and enhancements	XI.M39	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.12
One-Time Inspection Program (B.1.27)	New	Consistent	XI.M32	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.9
One-Time Inspection - Small Bore Piping Program (B.1.28)	New	Consistent	XI.M35	reactor vessel, internals and reactor coolant system	3.0.3.1.10
Periodic Surveillance and Preventive Maintenance Program (B.1.29)	Existing	Plant-specific		engineered safety features systems / auxiliary systems / steam and power conversion systems / structures and component supports	3.0.3.3.7
Reactor Head Closure Studs Program (B.1.30)	Existing	Consistent	XI.M3	reactor vessel, internals and reactor coolant system	3.0.3.1.11
Reactor Vessel Head Penetration Inspection Program (B.1.31)	Existing	Consistent	XI.M11A	reactor vessel, internals and reactor coolant system	3.0.3.1.12
Reactor Vessel Surveillance Program (B.1.32)	Existing	Consistent with enhancement	XI.M31	reactor vessel, internals and reactor coolant system	3.0.3.2.13
Selective Leaching Program (B.1.33)	New	Consistent	XI.M33	engineered safety features systems / auxiliary systems	3.0.3.1.13

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Service Water Integrity Program (B.1.34)	Existing	Consistent	XI.M20	auxiliary systems	3.0.3.1.14
Steam Generator Integrity Program (B.1.35)	Existing	Consistent with enhancement	XI.M19	reactor vessel, internals and reactor coolant system	3.0.3.2.14
Structures Monitoring Program (B.1.36)	Existing	Consistent with enhancements	XI.S6 and XI.M23	structures and component supports	3.0.3.2.15
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.1.37)	New	Consistent	XI.M12	reactor vessel, internals and reactor coolant system	3.0.3.1.15
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program (B.1.38)	New	Consistent	XI.M13	reactor vessel, internals and reactor coolant system	3.0.3.1.16
Water Chemistry Control - Auxiliary Systems Program (B.1.39)	Existing	Plant-specific		engineered safety features systems / auxiliary systems	3.0.3.3.8
Water Chemistry Control - Closed Cooling Water Program (B.1.40)	Existing	Consistent with exceptions and enhancements	XI.M21	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems	3.0.3.2.16
Water Chemistry Control - Primary and Secondary Program (B.1.41)	Existing	Consistent with enhancement	XI.M2	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems / structures and component supports	3.0.3.2.17

3.0.3.1 Programs Consistent with the GALL Report

In LRA Appendix B, the applicant described the following programs as consistent with the GALL Report:

- Boric Acid Corrosion Prevention Program
- Buried Piping and Tanks Inspection Program

- Containment Leak Rate Program
- Environmental Qualification of Electric Components Program
- Flow-Accelerated Corrosion Program
- Non-EQ Inaccessible Medium-Voltage Cable Program
- Non-EQ Instrumentation Circuits Test Review Program
- Non-EQ Insulated Cables and Connections Program
- One-Time Inspection Program
- One-Time Inspection - Small Bore Piping Program
- Reactor Head Closure Studs Program
- Reactor Vessel Head Penetration Inspection Program
- Selective Leaching Program
- Service Water Integrity Program
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program

3.0.3.1.1 Boric Acid Corrosion Prevention Program

Summary of Technical Information in the Application. LRA Section B.1.5 describes the existing Boric Acid Corrosion Prevention Program as consistent with GALL AMP XI.M10, "Boric Acid Corrosion."

The Boric Acid Corrosion Prevention Program implements Generic Letter (GL) 88-05 recommendations to monitor the condition of components on which borated reactor water may leak. The program detects boric acid leakage by periodic visual inspection of (a) systems containing borated water for deposits of boric acid crystals and the presence of moisture and (b) adjacent structures, components, and supports, for evidence of leakage. This program, which manages loss of material and loss of circuit continuity, evaluates leakage discovered by other activities. The applicant has made program improvements as suggested in NRC Regulatory Issue Summary (RIS) 2003-013.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Boric Acid Corrosion Prevention Program and basis documents to verify consistency with GALL AMP XI.M10. Details of the staff's audit of the applicant's AMP are documented in the Audit Report (ADAMS Accession No. ML083540662). As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M10. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.5 states that inspections of the IP2 containment building in April 2005, November 2005, and May 2006 detected minor boron leakage. Also, a March 2005 inspection detected boron leakage at IP3 reactor coolant boundary components that may be subject to boric acid leakage and corrosion. The applicant stated that early detection prevented boric acid wastage of affected components and adjacent structures and components. It further stated that detection of degradation followed by corrective action prior to loss of intended function has proven that the program effectively manages aging effects for passive components.

LRA Section B.1.5 also states that the Boric Acid Corrosion Prevention Program was enhanced to include recommendations of the Westinghouse Owner's Group Westinghouse Commercial Atomic Power (WCAP)-15988-NP, "Generic Guidance to Best Practice 88-05 Boric Acid Inspection Program," Electric Power Research Institute (EPRI) Technical Report 1000975, "Boric Acid Corrosion Guidebook," and NRC Bulletin 2003-02 "Leakage from Reactor Coolant Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity." Ongoing program improvements, through incorporation of lessons learned from industry operating experience, assure continued effective management of aging effects for passive components.

The applicant has reported leakage from Conoseals at both IP2 and IP3 but there was no measurable material degradation on the vessel head as a result of the boric acid leakage. The applicant has stated that the most common cause of failure for bolts in the industry is boric acid corrosion which is documented in EPRI Mechanical Tools (EPRI 1010639) and Non-Class 1 Mechanical Implementation guidelines.

During the audit and review of this AMP, the staff asked the applicant whether they had observed leakage from Conoseal flanges (Audit Item 109). By letter dated March 24, 2008, the applicant stated that both IP2 and IP3 have experienced Conoseal leaks during the past few operating cycles. At IP2, the most recent leak occurred at penetration #95, during the current operating cycle. At IP3, the most recent leak was detected during the Spring 07 refueling outage. The applicant stated that the Conoseals at IP2 and IP3 have been modified to minimize the possibility of future leakage. All of the recent leaks have been eliminated with the exception of the current leak at Penetration #95. The applicant stated that the boric acid was cleaned up and the vessel head was examined for material degradation and that it did not detect any degradation in the areas exposed to boric acid deposits.

The staff verified that the applicant had taken appropriate corrective actions to clean off the boric acid residues that developed on the IP2 and IP3 upper reactor vessel (RV) heads as a result of Conoseal leakage. The staff also noted that applicant's corrective actions included an evaluation of the upper RV head wall thickness and that in the corrective actions documentation the applicant had demonstrated that the Conoseal leakage did not result in any detectable boric acid-induced wastage (i.e., loss of material degradation) in the upper RV closure heads. Based on this review, the staff finds that the applicant's program monitors for Conoseal leakage and that the applicant takes appropriate corrective actions when Conoseal leakage is detected.

By letter dated May 7, 2008, in RAI RCS-1, the staff inquired about other operating experience (condition reports that had been issued on boric acid leakage of ASME Code Class 1 components). By letter dated June 5, 2008, the applicant stated, in part, that the routine inspections of control rod drives, control rod drive mechanisms, resistance temperature devices, RV lower heads, RV bottom mounted instrumentation (BMI) nozzles, RV seal tables, RV fittings, and RV flux thimble tubes at IP2 and IP3 from 2001 – 2005 revealed indications of boric acid leakage that could potentially lead to loss of material due to boric acid corrosion. The applicant stated that it had taken appropriate corrective actions to correct the adverse conditions, including cleaning of the affected Class 1 areas to remove boric acid residues from the components, replacing leaking gaskets, repair of leaking welds or components, and revisions to the implementing procedures for foreign material (boric acid residue) control and for visual inspections of the RVs. The applicant stated that the components, after boric acid residue cleaning, were determined to be acceptable for further service.

The staff noted that the applicant's response indicates that the applicant's augmented Boric Acid Corrosion Prevention Program is achieving its function of monitoring and detecting evidence of borated reactor coolant leakage from the applicant's ASME Code Class 1 reactor coolant pressure boundary components, and that the applicant is taking appropriate corrective actions when borated reactor coolant leakage is detected as part of the applicant's implementation of the program.

Thus, the staff finds that the applicant has addressed relevant operating experience that is applicable to this AMP, and that, based on the applicant's detection of boric acid residues and corrective actions to correct adverse boric acid residue conditions, the applicant has demonstrated that the program is effective and will be capable of detecting borated reactor coolant leakage from ASME Code Class 1 reactor pressure boundary components and RV Conoseals during the period of extended operation. RAI RCS-1 is resolved with respect to operating experience that is relevant to this AMP.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.4 and A.3.1.4, the applicant provided the UFSAR supplement for the Boric Acid Corrosion Prevention Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Boric Acid Corrosion Prevention Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.6 describes the Buried Piping and Tanks Inspection Program as a new program that will be consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

The Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program finds susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement. The program applies to buried components in the following systems.

- safety injection
- service water
- fire protection
- fuel oil
- security generator
- city water
- plant drains
- auxiliary feedwater
- containment isolation support

Of these systems, only the safety injection system contains radioactive fluids during normal operations. Safety injection system buried components are stainless steel. This system uses stainless steel for its corrosion resistance.

By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant submitted an amendment to the LRA which modified the Buried Piping and Tanks Inspection Program. This amendment was in response to recent operating history which involved a February 2009 leak on the return line to the condensate storage tank (CST) for Unit 2. As a result of this operating experience, the applicant plans to include a risk assessment to classify in-scope buried piping segments and buried tanks as high, medium, or low impact of leakage based on the safety classification, the hazard posed by the fluids in the piping and tanks, and the impact of leakage on reliable plant operation. The applicant will consider the piping or tank material of construction, soil resistivity, drainage, the presence of cathodic protection, and the type of coating for corrosion risk.

The applicant's modification to the Buried Piping and Tanks Inspection Program significantly increases the number of inspections of buried piping and tanks. Rather than conduct one inspection prior to entering the period of extended operation, consistent with the GALL Report where site-specific operating experience is not a factor, the applicant will conduct 15 periodic inspections for IP2 prior to entering the period of extended operation in 2013, and 30 periodic inspections for IP3 prior to entering the period of extended operation in 2015. Also, because of the recent leak in the CST return line, the applicant plans to conduct six additional inspections in 2009 at lower level elevations for the service water and auxiliary feedwater systems, based on a determination that these locations have the highest risk of corrosion due to their proximity to the water table.

The applicant stated that it will employ inspection methods with demonstrated effectiveness for detection of aging effects in buried components such as those currently being evaluated by the Electric Power Research Institute. One example is guided wave ultrasonic testing (UT). The applicant further stated that it is actively participating in the industry group established to address issues with degradation of buried components.

With respect to inspections to be performed during the period of extended operation, the applicant stated that the number of inspections and inspection frequency will be based on the results of the planned inspections prior to the period of extended operation, other applicable industry and plant-specific operating experience, and its risk assessment.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements and basis documents of the Buried Piping and Tanks Inspection Program to verify consistency with GALL AMP XI.M34. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M34. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During the audit, the staff asked the applicant if any buried tanks are in scope for license renewal (Audit Item 110). By letter dated March 24, 2008, the applicant stated that the following tanks are buried and in scope for license renewal and are included in the Buried Piping and Tanks Inspection Program:

- IP2 Fuel Oil Storage Tanks (21/22/23 FOST)
- GT1 Fuel Oil Storage North and South Storage Tanks
- IP2 Security Diesel Fuel Tank
- IP3 Appendix R Fuel Oil Storage Tank (EDG-33-FO-STNK)
- IP3 Security Propane Fuel Tanks (2 of them)
- IP3 Fuel Oil Storage tanks (EDG-31/32/33-FO-STNK).

The applicant's discovery of a leak in the CST return line was documented in NRC Inspection Report 05000247/2009002, dated May 14, 2009. As a result of this leak, the applicant revised its Buried Piping and Tanks Inspection Program, in a letter dated July 27, 2009, as clarified by letter dated August 6, 2009. The staff reviewed the revised program to assure acceptability of the revised inspection plans. The staff found that the applicant's enhanced inspection plans provide a significant increase in the number of locations to be examined prior to the period of extended operation, from one per unit to a combined total of 51 inspections for the two units. These inspections will focus on the buried piping and tanks that are within the scope of the Buried Piping and Tanks Inspection Program. The applicant plans to prioritize the inspection locations based on a risk assessment that identifies high, medium and low impact of leakage at that location based on the safety classification, the hazard posed by the fluid, the potential impact of leakage on reliable plant operation, and the corrosion risk of the location. As described by the applicant, the corrosion risk appears to consider those parameters that will reasonably characterize the corrosion likelihood for the location. Overall, the staff finds that this approach for determining the specific locations for inspection and the large increase in the number of locations to be inspected provide a significant enhancement in the program prior to entering the period of extended operation, beyond that described in the GALL Report. The staff finds that the scope of this enhancement is reasonable in light of the recent operating experience at IP.

In its letter of July 27, 2009, as clarified by letter dated August 6, 2009, the applicant stated that additional periodic inspections will be conducted during the first 10 years of the period of extended operation. The applicant further stated that the frequency and number of these periodic inspections will be determined based on the results of the inspections that will be conducted and completed prior to entering the period of extended operation, in addition to the risk assessment of the piping segments and tanks. The staff finds that the applicant's commitment to consider the results of the inspections conducted prior to the period of extended operation in its subsequent inspection program is reasonable.

The use of inspection methods with demonstrated effectiveness for detection of aging effects, as proposed by the applicant for inspections both prior to and during the period of extended operation, provides reasonable assurance of the effectiveness of the technique. Specifically, the technique is to be evaluated by a third party, the EPRI NDE Center, and would be demonstrated to be capable of detecting degradation (e.g., cracks, corrosion) in samples that are similar to the configuration and types of degradation that may be present at the IP site. The staff finds the use of inspection methods with demonstrated effectiveness to be an acceptable and appropriate aspect of this program.

The staff finds that with the numerous enhancements to the GALL Buried Piping and Tanks Inspection Program, the applicant's program is acceptable. The applicant has significantly increased the number of inspections of buried piping beyond that which is recommended in the GALL Report AMP prior to entering the period of extended operation. In addition, the applicant's commitment to perform additional periodic inspections using inspection methods with demonstrated effectiveness during the first 10 years of the period of extended operation, with the frequency and priority of inspections to be determined based on operating experience and risk assessment of the piping segments and tanks, provides reasonable assurance that the applicant will be able to adequately manage the effects of aging of its buried piping and tanks during the period of extended operation.

Operating Experience. LRA Section B.1.6 states that the Buried Piping and Tanks Inspection Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. IP plant-specific operating experience is consistent with the operating experience in the GALL Report program description.

The applicant stated that the IP program is based on the GALL Report program description, which in turn is based on industry operating experience, assurance that the Buried Piping and Tanks Inspection Program will manage the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

In Audit Item 110, the staff asked the applicant if IP2 or IP3 had to replace any buried piping or had to replace or repair any sections of buried pipe. In its response, dated March 24, 2008, the applicant stated that a review of site condition reports back to 2000 revealed that there have been two underground piping leaks that occurred on the auxiliary steam supply cross connect line between Unit 2 and Unit 3. This piping is nonsafety-related and is not within the scope of license renewal. The first leak occurred in 2002 and a condition report was written for this leak. The leak was repaired via the work control process. The applicant further stated that a second leak occurred in April 2007 and was documented in a condition report. This line has been excavated and replaced. The cause of the failure was determined to be advanced corrosion of the pipe due to moisture intrusion. This was caused by the pipe coating breaking down and insulation that was not sufficient for the task. After replacement, the pipe was reinsulated using a special high temperature moisture resistant material that was designed to prevent this type of corrosion in the future. The applicant stated that no other buried piping repair or replacement was identified during its review of operating experience.

By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant identified additional operating experience concerning coating degradation identified during the fall of 2008, and a February 2009 leak on the return line to the CST on Unit 2.

During the fall of 2008, the applicant performed inspections of three 10-foot sections of Unit 2 CST piping and found damaged coating and two locations with minor coating defects. The damaged coating was repaired. Ultrasonic testing measurements confirmed that the pipe thickness remained at nominal thickness, within the manufacturer's tolerance.

In February 2009, the applicant identified a leak in the IP2 return line to the CST. The applicant stated that there was no safety significance to the leak because there was sufficient inventory for the CST to perform its intended function. The applicant stated that the leak occurred as a result of damage to the coating on the pipe, which it concluded occurred during original construction. In particular, the applicant concluded that the damage occurred because the construction installation specification did not specify the type of backfill for covering the pipe, permitting rocks in the backfill. The location of the leak was close to the water table, and moisture in the soil may have contributed to the damage. The applicant replaced the section of pipe containing the leak and repaired several additional thinned areas on the pipe. The affected areas were recoated and the applicant used improved backfill specifications to cover the pipe. The staff at headquarters coordinated with NRC Region I inspectors who followed up on the licensee's corrective actions on site.

Based on its review, the staff concludes that the applicant has appropriately considered operating experience for the Buried Piping and Tanks Inspection Program. Further, the staff concludes that the applicant's "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element to be acceptable.

UFSAR Supplement. In LRA Sections A.2.1.5 and A.3.1.5, the applicant provided the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The applicant committed to implement the Buried Piping and Tanks Inspection Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, "Buried Piping and Tanks Inspection" (Commitment 3). By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant modified Commitment 3 to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The applicant changed the inspections from "opportunistic" to periodic, and committed to establish the inspection priority and frequency based, in part, on the results from its planned inspections prior to entering the period of extended operation and other applicable industry and plant-specific operating experience. Further, the applicant committed to perform inspections using inspection methods with demonstrated effectiveness. The applicant also modified LRA Sections A.2.1.5, A.3.1.5, and B.1.6 to incorporate the changes to the Buried Piping and Tanks Inspection Program.

The staff reviewed these sections, as revised, and determines that the information provided in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Containment Leak Rate Program

Summary of Technical Information in the Application. LRA Section B.1.7 describes the existing Containment Leak Rate Program as consistent with GALL AMP XI.S4, "10 CFR 50, Appendix J."

The applicant states that the Containment Leak Rate Program, as described in 10 CFR Part 50, Appendix J, requires containment leak rate tests to assure that (a) leakage through primary reactor containment, and systems and components penetrating primary containment shall not exceed allowable values specified in technical specifications or their bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating containment. The applicant furthers states that the IP2 and IP3 program utilizes 10 CFR 50 Appendix J, Option B, and the guidance in RG 1.163, and the recommendations in NEI 94-01.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Containment Leak Rate Program and basis documents to verify consistency with GALL AMP XI.S4. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.S4. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.7 states that in 2006 (Unit 2 refueling outage 17, 2R17), containment leak rate testing at IP2 was completed successfully. The applicant states that a QA surveillance of the containment leak rate test found only administrative deficiencies in the procedures for calculating total leakage. Results from the 2005 (Unit 3 refueling outage 13, 3R13) IP3 containment leak rate testing were satisfactory. Confirmation of containment integrity, along with detection and resolution of program discrepancies, assure effective program management of loss of component material.

The applicant also states that an industry benchmarking for this program in 2004 found areas for improvement and implemented corrective actions. A 2003 self-assessment of the program focused on differences between the IP2 and IP3 program procedures and took actions that led to several improvements.

The applicant concluded that its program is consistent with the GALL Report, Option B program, stating that review of operating history, corrective actions, and self-assessments shows the Containment Leak Rate Program is monitored and enhanced continually to incorporate operating experience and is effective in ensuring the structural integrity and leak tightness of the IP2 and IP3 containments.

During an onsite audit, the staff reviewed the program basis documents discussion of operating experience, which summarize the operating experience of the Containment Leakage Rate Program, as well as the results of past leakage rate tests of the containment at IP2 and IP3. In addition, the documents describe other industry benchmarking and focused self-assessment of the Containment Leakage Rate Program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.6 and A.3.1.6, the applicant provided the UFSAR supplement for the Containment Leak Rate Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Containment Leak Rate Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 Environmental Qualification of Electric Components Program

Summary of Technical Information in the Application. LRA Section B.1.10 describes the existing Environmental Qualification of Electric Components Program as consistent with the GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components."

The applicant stated that the Environmental Qualification of Electric Component Program is an existing program. The NRC has established nuclear station EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electric components located in harsh environments (that is, those areas of plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line breaks (HELBs) or high radiation) are qualified to perform their safety function in those harsh environments. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ. The applicant further stated that the IP EQ program manages the effects of thermal, radiation, and cyclic 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 are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components are TLAAs for license renewal.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Environmental Qualification of Electric Components Program and basis documents to verify consistency with the GALL Report AMP X.E1. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP X.E1. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.10 states that in August 2001, the applicant identified incorrect inputs in the EQ analyses. As part of its corrective actions, the applicant stated that it updated calculations and evaluated other program documents and environmental conditions. The applicant also stated that, in July 2002, a QA audit of the program found differences between the analytical tools for high-energy line break analyses at IP2 and IP3. As part of corrective actions, the applicant developed revised pressure-temperature (P-T) profiles and thermal lag evaluations for specific equipment and revised the EQ program plan and supporting calculations. The applicant further stated that a focused self-assessment in 2002 found that program procurement and work control processes complied with 10 CFR 50.49 and that in February 2003, the EQ program was reviewed to determine the impact of the IP2 power uprate. Those EQ files which required update were revised. In 2003-2004, an EQ master list validation project led to wiring diagram reviews and master list updates.

The staff interviewed the applicant's technical staff and reviewed the program basis documents. During the discussion of the EQ program with the applicant, the staff requested the applicant to provide additional operating experience (OE) associated with the EQ program (Audit Item 160). In a letter dated March 24, 2008, the applicant stated that in January 2006, during an EQ program enhancement project, it discovered that an EQ file did not identify or address qualification of pigtail extension cables. A condition report (CR) was initiated to capture EQ documentation deficiency. The EQ program enhancement project was initiated to correct this type of discrepancy and test reports were obtained and evaluated. The applicable test report met the applicant's environmental parameter requirements; therefore, these cables were considered qualified.

The applicant further stated that it participates in several industry-based working and assessment groups, to ensure that the IP2 and IP3 EQ program stays current with the industry and that the industry OE is addressed. The industry groups are comprised of utility operators worldwide, the majority of which are in the US and Canada. Participation in these organizations also provides a source of regulatory and reference documents, component information, engineering analyses, and material data from many different manufacturers and utilities.

The staff finds that the operating experiences identified above and those identified in program basis documents demonstrate that identification of program weakness and timely corrective actions as part of the EQ program provide assurance that program will remain effective in assuring that equipment is maintained within its qualification basis and qualified life.

The staff confirmed that the "operating experience" program element meets the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.9 and A.3.1.9, the applicant provided the UFSAR supplement for the Environmental Qualification of Electric Components Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Environmental Qualification of Electric Components Program, the staff finds that all program elements are consistent with the GALL Report AMP X.E1. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 Flow-Accelerated Corrosion Program

Summary of Technical Information in the Application. LRA Section B.1.15 describes the existing Flow-Accelerated Corrosion (FAC) Program as consistent with GALL AMP XI.M17, "Flow-Accelerated Corrosion."

The Flow-Accelerated Corrosion Program applies to safety-related and nonsafety-related carbon and low-alloy steel components in systems containing high-energy fluids which carry two-phase or single-phase high-energy fluid for more than 2 percent of plant operating time. The program, based on EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," (April 1999) for an effective Flow-Accelerated Corrosion program, predicts, detects, and monitors flow-accelerated corrosion in plant piping and other pressure-retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions or to repair or replace components as necessary.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Flow-Accelerated Corrosion Program and basis documents to verify consistency with the GALL Report AMP XI.M17. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M17. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the "corrective actions" program element for this AMP with respect to verifying whether repair/replacement activities for in-scope components involved replacement with components using FAC-resistant materials. The staff reviews this aspect of the "corrective actions program element later in the evaluation of the applicant response to Part 2 of RAI B.1.15-2.

However, during its review of the applicant's program, the staff identified the following aspects that needed additional clarification: (1) the scope of the applicant's program, (2) evaluation of the exception in the program to use EPRI Report NSAC-202L-R3, "Recommendations for an Effective Flow-Accelerated Corrosion Program," (May 2006) as the implementation guideline document for the applicant's program, (3) resolution of RAI B.1.15-1 on whether the AMRs in the LRA credit this program to manage loss of material due to flow-accelerated corrosion for the carbon steel components in the steam generator (SG) blowdown system, and (4) resolution of RAI B.1.15-2, Parts 1, 2, and 3, on how CHECWORKS™ modeling is performed, how power uprate conditions are incorporated into this modeling, and on which in-scope systems at IP2 and IP3 are considered as being the most susceptible to flow-accelerated corrosion. The staff evaluates these aspects of the applicant's program in the italicized subsections that follow.

Clarification on the Scope of Program

The NRC discussed the establishment and implementation of Flow-Accelerated Corrosion Programs in NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants" (July 9, 1987) and in Generic Letter (GL) 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" (May 2, 1989). The staff verified that the applicant responded to Bulletin 87-01 for IP2 in a letter dated September 11, 1987 (NRC Microfiche Address 42741, Pages 199-233) and for IP3 in a letter dated September 15, 1987 (NRC Microfiche Address 42739, Pages 131-146). The staff verified that the applicant responded to GL 89-08 for IP2 in a letter dated July 20, 1989 (NRC Microfiche Address 50726, Pages 331-332) and for IP3 in a letter dated July 21, 1989 (NRC Microfiche Address 50737, Pages 100-102). The staff verified that these responses were the docketed documents that initially defined the systems that are within the scope of the applicant's Flow Accelerated Corrosion Programs for IP2 and IP3, and defined how the programs would be implemented. The staff verified that the scope of the applicant's Flow-Accelerated Corrosion Program includes these generic communication responses.

In the "operating experience" program element in GALL AMP XI.M17, "Flow Accelerated Corrosion," the staff clearly identified that single-phase feedwater and condensate systems and two-phase extraction steam, moisture separator reheater drain, and feedwater heater drain systems are among the PWR plant systems that are the most susceptible to loss of material (erosion) by flow-accelerated corrosion. From its review of the applicant's responses to Bulletin 87-01 and GL 89-08 for IP2 and IP3, the staff verified that the scope of the programs for IP2 and IP3 includes those systems that contain carbon steel or alloy steel components that are exposed to high velocity, single-phase water-based flow environment or high velocity, two-phase water-steam environments, and, as a minimum, the feedwater, condensate, extraction steam, moisture separator reheater drain, and feedwater heater drain systems, as recommended for inclusion in the AMP according to the "operating experience" and "reference" sections of GALL AMP XI.M17, "Flow-Accelerated Corrosion." The staff also noted from the applicant's responses to these generic communications, that the programs developed in response to Bulletin 87-01 and GL 89-08 includes the following additional systems:

- Auxiliary feedwater systems (as indicated in the Bulletin 87-01 response for IP2 and the GL 89-08 response for IP3)
- Steam generator (SG) blowdown systems (as indicated in the Bulletin 87-01 response for IP2 and the GL 89-08 response for IP3)

- Turbine generator cross-under piping, including pre-separators (as indicated in the Bulletin 87-01 response for IP2)
- Heater drain pump discharge piping (as indicated in the Bulletin 87-01 response for IP2)
- Main steam system (as indicated in the GL 89-08 response for IP3)
- Reheater drain system (as indicated in the GL 89-08 response for IP3)
- Auxiliary Steam System (as indicated in the GL 89-08 response for IP3)

The staff finds that the inclusion of these additional systems within the scope of the applicant's program is acceptable because it represents an additional scoping conservatism in the program beyond the feedwater, condensate, extraction steam, moisture separator reheater drain, and feedwater heater drain systems that were included in the program in response to the NRC's safety-significant FAC-related generic communications that have been identified in "operating experience" program element of GALL AMP XI.M17.

Based on this review, the staff finds that the scope of program element for the Flow-Accelerated Corrosion Program is acceptable because: (1) the scope of the program includes the applicant's responses to Bulletin 87-01 and GL 89-08, (2) the scope of the program includes the feedwater, condensate, extraction steam, moisture separator reheater drain, and feedwater heater drain systems, which are the plant systems that the staff has identified as being highly susceptible to loss of material by flow-accelerated corrosion, (3) the scope of the program includes additional plant systems that the applicant has also identified as being potentially susceptible to flow-accelerated corrosion, and (4) the scope of the program is consistent with NRC-identified, industry-identified, IP2-specific, and IP3-specific operating experience.

Exception to use EPRI Report NSAC-202L-R3

The staff noted that in the "scope of program" and "detection of aging effects" program elements of GALL AMP XI.M17, "Flow-Accelerated Corrosion," the staff recognizes EPRI Report NSAC-202L-R2 as a suitable guidance document for implementing flow-accelerated corrosion programs. The staff also noted that the applicant indicated that, instead of using Revision 2, Entergy is implementing Revision 3 for implementation of the applicant's program, and that the applicant did not identify this inconsistency as an exception to the "scope of program" and "detection of aging effects" program elements of GALL AMP XI.M17.

In Audit Item 156, the staff asked the applicant to justify its use of Revision 3, and why the use of the later version of the report was not indentified as an exception to the aging management criteria that are given in the "scope of program" and "detection of aging effects" program elements of GALL AMP XI.M17. By letter dated December 18, 2007, the applicant stated that the changes made from NSAC-202L-R2 to NSAC-202L-R3 basically accomplished the following improvements in the report that made for better FAC-management guidance on the "scope of program" and "detection of aging effects" program elements for the AMP:

1. "scope of program" – (1) administrative relocation of the guidance for system selection within the scope of the program, (2) reorganization of the guidance for selecting components for inspection for those systems that are within the scope of the program, (3) enhancement of the guidance for component sample selection to provide clarification and details on sample selection for both modeled piping lines and non-modeled piping

lines that are within the scope of the program, (4) addition of enhanced guidance for using plant-specific and industry-generic operating experience as an additional basis for selecting components for inspection, and (5) improved, enhanced guidance for sample expansion upon detection of relevant FAC-induced indications.

2. "detection of aging effects" – (1) additional clarification on the use of volumetric inspection techniques, including UT and radiographic testing (RT) for the detection of loss of material as a result of FAC, (2) additional guidance for the inspection of in-scope vessels and tanks, (3) enhancement of the inspection guidance for turbine cross-around piping, valves, orifices and equipment nozzles, and (4) additional guidance of the basis for the use of RT as an volumetric technique for large bore piping.

The staff verified that the updated guidance in NSAC-202L-R3 did not change: (1) the guidelines basis for excluding components from examination based on their materials of fabrication and material alloying contents, operational characteristics (for components not in service or infrequently in service), the dissolved oxygen contents of the single-phase or two-phase environments that the components are subjected to, or the flow velocities for the single-phase or two-phase environments that the components are subjected to, (2) the UT inspection criteria in NSAC-202L-R2 that components to be inspected around their girths and over a distance equivalent to least ± two pipe diameters of the subject welds or components scheduled for inspection, (3) the minimum wall thickness acceptance criteria for in-scope components, and (4) the repair/replacement criteria for components that do not meet the acceptance criteria of the report.

The staff also noted that the stated changes to the EPRI NSAC report provide for better programmatic guidance because they: (1) provide for enhanced guidance on how to apply relevant industry experience and plant-specific experience as an additional basis for selecting and scheduling additional components for UT or RT inspection, (2) provide for enhanced guidance on sample expansion if relevant indications of loss of material by flow-accelerated corrosion or other loss of material mechanisms are detected, (3) provide for enhanced guidance for inspection of in-scope tanks, cross-around piping, and small bore piping, and (4) provide addition clarifications on how to apply UT and RT as a volumetric inspection techniques for these programs.

The staff verified that, in the applicant's letter of December 18, 2007, the applicant amended the "scope of program" and "detection of aging effects" program elements in AMP B.1.15, Flow-Accelerated Corrosion Program, to identify use of EPRI Report NSAC-202L-R3 as an exception to the implementation guidance document that is recommended in the "scope of program" and "detection of aging effects" program elements of GALL AMP XI.M17, "Flow-Accelerated Corrosion." Thus, based on this review, the staff finds that EPRI Report NSAC-202L-R3 is an acceptable alternative and updated version of the EPRI NSAC guidelines for managing loss of material due to flow-accelerated corrosion at IP2 and IP3 because: (1) the updated version of the report in EPRI Report NSAC-202L-R3 has not led to any non conservatisms in the report's core guidance recommendations for inspecting of in-scope carbon steel or low-chromium content alloy steel components, for establishing the acceptance criteria for these components, or for repairing or replacing components if unacceptable indications of loss of material are detected in the components, and (2) the staff has verified that the applicant has amended the LRA to identify the use of EPRI Report NSAC-202L-R3 as an exception to the "scope of program" and "detection of aging effects" program elements in GALL AMP XI.M17. NRC Audit Item 156 is resolved.

Resolution of RAI B.1.15-1

The staff also noted that in the AMR items for the LRA, the applicant credited only its Water Chemistry Control-Primary and Secondary Program for managing loss of material in the steam generator blowdown nozzle carbon steel interior surface. In RAI B.1.15-1, dated December 7, 2007, the staff questioned whether degradation of these nozzles would be more appropriately managed by the Flow-Accelerated Corrosion Program.

In its response, dated January 4, 2008, the applicant stated that "[t]he blowdown system piping external to the steam generators is susceptible to loss of material due to flow accelerated corrosion and is managed by the Flow Accelerated Corrosion Program. The steam generator blowdown nozzles are part of the blowdown system piping and are included in the FAC program."

In addition, the applicant stated that the corresponding AMR entries to LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 would be revised to include a statement in Table 3.1.1 AMR Item 3.1.1-59 that will state that the carbon steel steam generator (SG) blowdown pipe connection is susceptible to FAC and that the Flow-Accelerated Corrosion Program is credited to manage loss of material due to FAC in these components.

The staff verified that the applicant amended the LRA by letter dated January 4, 2008, to: (1) amend the applicable AMRs for carbon steel SG blowdown piping to identify loss of material due to flow-accelerated corrosion as an applicable aging effect requiring management (AERM) for the interior piping surfaces that are exposed to treated water, (2) amend the applicable AMRs to credit the Flow-Accelerated Corrosion Program for management of this aging effect, and (3) amend LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 to add component type "blowdown pipe connection (nozzle)." Based on the applicant's explicit inclusion of the above components in the Flow-Accelerated Corrosion Program, the staff finds the applicant's response to RAI B.1.15-1 to be acceptable because the applicant has amended the scope of the Flow-Accelerated Corrosion program to include the SG blowdown piping system, and because the applicant has amended its AMRs to include AMRs on loss of material due to flow-accelerated of the carbon steel or alloy steel SG blowdown system piping, piping components, and pipe fittings that credit this program for aging management. The staff's concern described in RAI B1.15-1 is resolved.

Based on this review, the staff finds that the "scope of program" program element for the Flow-Accelerated Corrosion Program is acceptable because: (1) the applicant has identified components within the scope of the program are those carbon steel/low chromium-content alloy steel plant components that are in systems within the scope of license renewal and are subject to high-velocity/high energy single-phase or two-phase aqueous environments, (2) the program, as amended, is consistent with the program element criteria in GALL AMP XI.M17.

Resolution of RAI B.1.15-2, Parts 1, 2, and 3

The staff noted that IP2 and IP3 have implemented stretch power uprates (SPU) within the last three years. To assess the impact that these SPUs would have on the modeling and predictions of the CHECWORKS™ program, the staff issued RAI B.1.15-2 on December 7, 2007 to the applicant. In this three part RAI, the staff asked the applicant to: (1) provide details on any changes made to the Flow Accelerated Corrosion Program in order to account for changes that would need to be made to the process variables in CHECWORKS™ as a result of implementing these SPUs, (2) identify those in-scope piping systems and components that are currently most susceptible to loss of materials by flow-accelerated corrosion, and (3) clarify how accurately the CHECWORKS™ model has predicted changes in FAC wear rates for the top four most susceptible systems/components in each unit since the time the SPUs were implemented.

The applicant responded to RAI B.1.15-2 in a letter dated January 4, 2008. With respect to the applicant response to Part 1 of the RAI, the applicant stated that inputs to the IP2 and IP3 Flow-Accelerated Corrosion Programs were updated to include SPU operating parameter changes (*e.g.*, flow rates and operating temperatures), in addition to incorporating the results of previous wall thickness measurements into the CHECWORKS™ modeling to allow for updated FAC-induced wear rate predictions. The staff verified that the applicant's revised program used the CHECWORKS™ program as one of several bases for establishing which in-scope piping component locations should be scheduled for inspection at the next outage. The staff also verified that the applicant uses IP2-specific and IP3-specific operating experience, operating experience discussed in NRC generic communications, industry operating experience records or reports, and engineering judgment as additional bases for selecting in-scope piping components for inspection. The staff also verified that the applicant's use of the CHECWORKS™ program uses the most recent updated power-uprated operating parameters and the most current inspection results obtained from past inspections performed on components as the basis for establishing the program wear predictions for ferritic steel components that are within the scope of the program. Thus, the staff finds that the applicant has provided an acceptable basis for using CHECWORKS™ as one of several means for identifying components for inspection and for scheduling components for inspection at the next unit refueling outage because the current predictions from the computer model are based on the power uprated conditions and the most current inspection results for systems and components that are within the scope of and have been modeled by CHECWORKS™. Part 1 of RAI B.1.15-2 is resolved.

With respect to the applicant's response to Part 2 of RAI B.1.15-2, the applicant stated that the extraction steam system lines at IP2 and IP3 are the most susceptible plant systems for flow-accelerated corrosion, with the 3rd point extract steam lines between the high pressure turbines and the #23 feedwater heater being the most susceptible lines for IP2, and the 5th point extraction steam lines between the pre-separators and the #35 feedwater heater being the most susceptible lines for IP3. The staff finds that this is acceptable because it is consistent with the staff's operating experience discussions in NRC Information Notices (INs) 89-53 and 97-84 that FAC-induced full ruptures of extraction steam systems have occurred in the industry and that these systems are among plant systems most susceptible to FAC-induced erosion (i.e. loss of material due to FAC).

The applicant also clarified the majority of the most susceptible plant locations at IP2 and IP3 have been replaced with FAC-resistant materials. The staff verified that the applicant identifies (in the "operating experience" program element for this AMP) that the FAC-resistant materials are chromium-molybdenum (Cr-Mo) alloy steels. The staff noted that in EPRI Report No. NSAC-202L-R2 (which is endorsed in GALL AMP XI.M17) and in EPRI Report No. NSAC-202L-R3.(which is the version of the report currently being used by the applicant, and found to be an acceptable alternative by the staff), EPRI identifies that austenitic stainless steels or chromium-molybdenum (Cr-Mo) alloy steels with chromium alloying contents in excess of 0.75% Cr by weight are steel materials that have enhanced resistance to FAC-induced erosion (i.e. loss of material due to FAC). The staff finds that the applicant's basis for replacing susceptible components with Cr-Mo alloy steels is acceptable because, in the staff's endorsement of EPRI Report NSAC-202L-R2, the staff concurred that Cr-Mo alloy steels provide for added corrosion resistance to FAC. Thus, based on this review, the staff finds that the applicant has resolved Part 2 of RAI B.1.15-2 because: (1) the applicant's statement that the extraction steam systems are the plant systems most susceptible to flow-accelerated corrosion is consistent with the staff's discussions in INs 89-53 and 97-84 that extraction steam systems are among the plant systems that are most susceptible to FAC-induced erosion, and (2) the applicant has provide an acceptable basis for replacing susceptible components (including any components that have been identified to have an unacceptable amount of FAC-induced aging in them) with Cr-Mo alloy steel in-kind components. Part 2 to RAI B.1.15-2 is resolved.

With respect to the applicant's response to Part 3 of RAI B.1.15-2, the applicant provided the following clarification on how the CHECWORKS™ modeling accounted for SPU conditions and why prolonged benchmarking of the models predictive analytical modeling was not necessary:

> The input to the CHECWORKS modeling program includes plant operating parameters such as flow rates, operating temperatures and piping configuration, as well as measured wall thicknesses from FAC program components. This input, in conjunction with the CHECWORKS predictive algorithm, is used to predict the rate of wall thinning and remaining service life on a component-by-component basis. The value of the model lies in its ability to predict wear rates based on changing parameters, such as flow rate, without having to have actual measured wall thickness values. The predictive algorithms built into CHECWORKS are based on available laboratory data and FAC data from many plants. CHECWORKS was designed, and has been shown, to handle large changes in chemistry, flow rate and or other operating conditions. In its use throughout the industry, the CHECWORKS model has been benchmarked against measurements of wall thinning for components operating over a wide range of flow rates. Consequently, the validity of the model does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions. In addition, by the time IPEC enters the period of extended operation (in the year 2013), inspection data under SPU conditions will have been obtained. These additional data sets, when added to the CHECWORKS database, will result in more refined wear rate predictions. Since the previously most susceptible locations have been replaced, wear rates are low. Due to the low wear rates, the small changes in operating parameters due to SPU, and the relatively short time since SPU, changes to wear rates since SPU will be very small. The accuracy of the model is not expected to change significantly due to the SPU.

The staff noted that the applicant's response to RAI B.1.15-2 clearly explains how the CHECWORKS™ computer code is used as an analytical model for predicting which plant system and components should be inspected during scheduled outages in which the applicant can perform UT examinations of the components. With respect to the use of CHECWORKS™ as a predictive model, the staff noted that the CHECWORKS™ analytical model uses the actual configured plant design, plant operating characteristics and parameters (such as system operating temperature flow rates, pressure, and water chemistry values), and actual UT inspection results to establish a susceptibility ranking of the plant's steel components to wall thinning by flow-accelerated corrosion.

The staff also noted the modeling includes a feature to incorporate actual inspection wall thickness results back into the computer modeling, and that this feature is used to accomplish two important aspects of CHECWORKS™ predictive modeling capability: (1) it permits the user to compare that actual as-found wall component thickness measurements of an inspected component to the wall thickness for the component that was predicted by CHECWORKS™ in the previous modeling results, thus providing a method for confirming the degree of accuracy of the model's previous component wear rate predictions and component wall thickness predictions, and (2) it permits the user to perform re-baselined component wear rate predictions and component wall thickness predictions based on the incorporation of the compiled inspection data for components that are modeled by the computer code and are inspected as part of the applicant's Flow-Accelerated Corrosion Program. The staff considers this feature to be a self-benchmarking capability of the CHECWORKS™ model. The staff also verified that the applicant's implementation of the CHECWORKS™ computer code applies all of these features and that the modeling has incorporated the operating conditions and parameters from the IP2 and IP3 stretch power uprates.

The staff noted that CHECWORKS™ is endorsed in EPRI Report Nos. NSAC-202L-R2 and EPRI Report No. NSAC-202L-R3 only as one of a number of methods that should be used to predict which plant components are susceptible to FAC and which components should be inspected at scheduled refueling outages or replaced with in-kind components using FAC-resistant materials. The staff noted that these reports also state the relevant operating experience and engineering judgment are both invaluable additional tools that should used in establishing which components should be scheduled and inspected for wall thickness measurements. The staff verified that, in addition to use of CHECWORKS™, the applicant also uses IP2-specific and IP3-specific operating experience, industry-wide operating experience, operating experience identified in NRC-issued INs, GLs, and Bulletins, and engineering judgment as additional bases for selecting the steel piping, piping components, and piping elements for inspection. The staff also verified that the Flow-Accelerated Corrosion Program includes applicable acceptance criteria for evaluating in-scope components and applicable corrective actions (repair, replacement, or re-evaluation) for components that are projected to exhibit an unacceptable amount of FAC-induced wall thinning.

Since the applicant's program includes the incorporation of actual wall thickness measurement data into the CHECWORKS™ modeling, since the staff considers CHECWORKS™ to be a self-benchmarking compute code, and since the applicant does not limit CHECWORKS™ as being the only programmatic basis for selecting and scheduling components for inspection, the staff finds that it is unnecessary to require prolonged benchmarking of the CHECWORKS™ computer code in order to justify its use in the selection and scheduling of in-scope components for inspection. In addition, the staff has verified that the applicant's implementation of CHECWORKS™ as part of the applicant's program is consistent with the staff's recommendation in the "monitoring and trending" program element in GALL AMP XI.M17 that CHECWORKS™ be used as one of the bases for selecting and scheduling in-scope components for inspection. Based on this review, the staff finds that this approach for aging management of loss of material due to flow-accelerated corrosion is acceptable because it provides an adequate basis why prolonged benchmarking of CHECWORKS™ is unnecessary and because the applicant's implementation of CHECWORKS™ is in conformance with the staff's "monitoring and trending" program element criteria for aging management that are recommended in GALL AMP XI.M17, "Flow-Accelerated Corrosion." RAI B.1.15-2, Part 3 is resolved.

Based on this review, the staff concludes that the program elements for the applicant's Flow-Accelerated Corrosion Program, as amended, provide an adequate basis to manage flow-accelerated corrosion because: (1) CHECWORKS™ code is considered to be a self-benchmarking code that is capable of modeling, predicting, and tracking the results of the ultrasonic inspections that are performed in accordance with the applicant's Flow-Accelerated Corrosion Program, (2) the self-benchmarking feature of CHECWORKS™ makes prolonged benchmarking of CHECWORKS™ is unnecessary, (3) the applicant uses the actual UT inspection results to confirm the predictive modeling of the CHECWORKS™ analyses and to perform re-baselined CHECWORKS™ predictive analyses, (4) the applicant does not limit the use of the CHECWORKS™ computer code as the sole basis for establishing which steel piping, piping components, or piping elements at IP2 and IP3 will be inspected, and (5) the program includes acceptable program elements for managing flow-accelerated corrosion that are consistent with the program element criteria in GALL AMP XI.M17 or with the acceptable alternative to use EPRI Report NSAC-202L-R3 as the implementation guideline for this program.

Operating Experience. LRA Section B.1.15 states that the most recent updates of the respective CHECWORKS FAC models account for IP2 and IP3 operating experience, including inspection data from the outage inspections as well as the changes to FAC wear rates, due to the recent power uprates. These updates further calibrate the model; and, therefore, improve the accuracy of the wear predictions.

The applicant stated that the IP2 Flow-Accelerated Corrosion Program was audited in 2004. The audit team found this program effective and in compliance with NRC regulations, ASME code, EPRI standards, and Institute of Nuclear Power Operations (INPO) guidelines. Program compliance with industry standards and guidelines assures continued effective management of aging effects for passive components.

In the LRA, the applicant stated that in February 2006, it performed a self-assessment of the Flow-Accelerated Corrosion Program to evaluate its overall health and effectiveness. The assessment team concluded that the applicant has a well-organized and effective Flow-Accelerated Corrosion Program, consistent with the primary industry standards, and with no weaknesses or deficiencies that would indicate any negative impact on long-term monitoring of flow-accelerated corrosion.

Further, the applicant stated that in March 2005, during the 3R13 refueling outage, it detected wall thinning on vent chamber drain and high-pressure turbine drain components, which were replaced during that outage. The applicant stated that these systems are susceptible to flow-accelerated corrosion and are closely monitored. Susceptible sections of these systems are replaced with FAC-resistant chrome-moly material. All remaining inspected components were found acceptable for continued service. In May 2006, during the 2R17 refueling outage, the applicant detected wall thinning in a steam trap pipe, which was then replaced during that outage. The applicant concluded that detection of degradation and corrective action prior to loss of intended function assure effective program management of aging effects due to flow-accelerated corrosion.

As part of the development of a fleet-wide program procedure, Entergy performed a review of best practices for the Flow-Accelerated Corrosion Program at all Entergy sites. Guidance from the EPRI CHECWORKS™ User's Group was applied to this procedure. Program compliance with industry standards and use of fleet-wide best practices in the development of procedures assure continued effective management of aging effects for passive components.

The staff noted that relevant FAC-related operating experience for PWR facilities has been provided in the NRC INs, Bulletins, and GLs that are given in the "operating experience" and "reference" sections in GALL AMP XI.M17, "Flow-Accelerated Corrosion." The staff verified, through its review of the applicant's responses to Bulletin 87-01 and GL 89-08, that the applicant's program includes those plant systems that are addressed in these NRC generic communications. Based on this determination, the staff finds that this provides evidence that the applicant adjusts its program to account for relevant operating experience.

The staff also noted that one of the requests made in Bulletin 87-01 was for applicants to summarize the FAC-based inspections that they had performed prior to issuance of the bulletin on May 2, 1987. The staff verified that in the applicant's responses to Bulletin 87-01, the applicant provided a summary of the UT inspections that had been performed at IP2 and IP3 prior to issuance of the bulletin. The staff noted that in the applicant's summary of its inspection results, the applicant had provided both the nominal wall thicknesses and the as-found wall thicknesses of the components that had been inspected prior to Bulletin 87-01. The staff also noted that in the applicant's bulletin responses, the applicant had indicated those components that were scheduled for repair or replacement as a result of detection of an unacceptable degree of FAC-induced degradation in the components or because the existing amount of degradation in the components was projected to grow to an unacceptable level prior to the next outage in which re-inspections would be performed. Based on this information, the staff finds that the inspection results in the bulletin responses demonstrate that the applicant is appropriately performing UT inspections of the systems that include carbon steel or alloy steel components which are potentially susceptible to flow-accelerated corrosion and that the applicant takes appropriate corrective action to repair or replace those components based on relevant IP2 and IP3 FAC-related operating experience.

Based on its review of the applicant responses to Bulletin 87-01 and GL 89-08, and of relevant IP2-specific and IP3-specific operating experience and operating experience discussed in applicable FAC-related NRC generic communications, the staff concludes that the applicant appropriately assesses and adjusts its Flow-Accelerated Corrosion Program to account for relevant FAC-related operating experience and to adjust the "scope of program" and remaining program elements for the AMP in accordance with lessons learned from this operating experience.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.14 and A.3.1.14, the applicant provided the UFSAR supplements for the Flow-Accelerated Corrosion Program. By letter dated December 18, 2007, the applicant revised LRA Sections A.2.1.14, A.3.1.14, and B.1.15 to change the reference from NSAC-202L-R2 to NSAC-202L-R3. The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 Non-EQ Inaccessible Medium-Voltage Cable Program

Summary of Technical Information in the Application. LRA Section B.1.23 describes the Non-EQ Inaccessible Medium-Voltage Cable Program as a new program that will be consistent with the GALL Report AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The applicant stated that the Non-EQ Inaccessible Medium-Voltage Cable Program includes periodic inspections for water collection in cable manholes and tests cables. In-scope medium-voltage cables (*i.e.*, cables with operating voltage from 2 kV to 35 kV) exposed to significant moisture and voltage are tested at least every ten years for an indication of the condition of the conductor insulation. The program inspects for water accumulation in manholes at least every two years.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Non-EQ Inaccessible Medium-Voltage Cable Program and basis documents to verify consistency with the GALL Report AMP XI.E3. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Non-EQ Inaccessible Medium-Voltage Cable Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.E3. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience: In LRA Section B.1.23, the applicant states that the Non-EQ Inaccessible Medium-Voltage Cable Program is a new program. When implementing, the applicant will consider as its basis, industry operating experience in the operating experience element of the GALL Report program description. IP plant-specific operating experience is consistent with the operating experience in the GALL Report program description.

The applicant also stated that the IP program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant also stated that plant-specific operating experience is not inconsistent with that in the GALL Report. The applicant will consider industry and plant-specific operating experience when implementing the Non-EQ Inaccessible Medium-Voltage Cable Program to confirm the new program effectiveness. The applicant further stated that such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

SRP-LR Section A.1.2.3.10 provides guidance for staff review of operating experience. It states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. As stated above, the applicant stated that it will consider industry and plant-specific operating experience when implementing this program.

The NRC conducted its license renewal inspections in accordance with Inspection Procedure IP-71002 during the weeks of January 28th, February 11th, March 31st, and June 2nd of 2008. During the June 2008 inspection, the staff observed a scheduled quarterly preventive maintenance (PM) activity to open and inspect the IP3 manhole 36. The staff observed standing water with several cable splices submerged. These included two 6.9 kV cables, both associated with the station blackout/Appendix R diesel generator, and are within the scope of license renewal. The applicant pumped the water out of the manhole, and assessed the condition of the cable jackets and splices as acceptable. The staff reviewed the results of previous PM activities, and noted that water was typically found in the manhole at a depth sufficient to submerge at least the lower cable splices.

In GALL Report AMP XI.E3, under the detection of aging effects element, it recommends that the inspection for water collection should be performed based on actual plant experience with water accumulation in the manhole. However, the inspection frequency should be at least once every two years. The applicant currently performs quarterly PM activities to open the manholes and look for water accumulation. If water is found, as indicated by the applicant, the water is pumped out of the manhole. The applicant has considered and will continue to factor in plant operating experience when determining the frequency of inspection.

The staff has identified water in manholes as a generic, current operating plant issue in Information Notice 2002-12, "Submerged Safety-Related Electrical Cables," dated March 21, 2002, and in Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," dated February 7, 2007. The staff will address water in the manholes, for the current period of operation, through the reactor oversight process in accordance with the requirements of 10 CFR Part 50.

During review of the LRA, the staff determined that the Non-EQ Inaccessible Medium-Voltage Cable Program when implemented as described will ensure that the aging effects on inaccessible medium-voltage cables, due to exposure to significant moisture, will be adequately managed during the period of extended operation in accordance with the guidance in GALL Report, Section XI.E3. The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program which recommends the applicant to test the cables and to evaluate plant-specific and industry-wide operating experience to determine if the inspection frequency of the manholes should be increased to ensure that the cables will be maintained in a dry environment during the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.22 and A.3.1.22, the applicant provided the UFSAR supplement for the Non-EQ Inaccessible Medium-Voltage Cable Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant committed to implement the Non-EQ Inaccessible Medium-Voltage Cable Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" (Commitment 15).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Non-EQ Inaccessible Medium-Voltage Cable Program, the staff finds that all program elements are consistent with the GALL Report AMP XI.E3. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 Non-EQ Instrumentation Circuits Test Review Program

Summary of Technical Information in the Application: LRA Section B.1.24 describes the Non-EQ Instrumentation Circuits Test Review Program as a new program that will be consistent with the GALL Report AMP XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

The applicant stated that the Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized environments caused by heat, radiation, and moisture (i.e., neutron flux monitoring instrumentation) can be maintain consistent with the CLB through the period of extended operation. Most neutron flux monitoring system cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provide sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The applicant further stated that for neutron monitoring system cables that are disconnected during instrumentation calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. Engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the CLB through the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Non-EQ Instrumentation Circuits Test Review Program and basis documents to verify consistency with the GALL Report AMP XI.E2. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Non-EQ Instrumentation Circuits Test Review Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.E2 except for the following area. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Under the program element 1 (scope of the program), the GALL Report AMP XI.E2 states that this program applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low level signal applications that are sensitive to reduction in insulation resistance. In its Non-EQ Instrumentation Circuits Test Review Program, the applicant only included neutron monitoring system cables in the scope of the program. The staff requested the applicant to explain why high-range-radiation monitoring cables were not included in the program (Audit Item 64). The staff also requested the applicant to identify any other high voltage, low level signal cables and explain why these cables are not in scope under the Non-EQ Instrumentation Circuits Test Review Program. In a letter dated March 24, 2008, the applicant stated that although not explicitly listed, the high-range radiation monitoring cables were included in AMP B.1.24. The AMR included neutron monitoring circuits and high-range radiation monitoring circuits. The program description for AMP B.1.24 uses the phrase "(i.e., neutron monitoring instrumentation)." Since this was meant to be an example, the term "e.g." would have been a more appropriate choice than "i.e." The applicant also stated that:

> During the integrated plant assessment (IPA), the only high instrument voltage circuits with low signal values that were not subject to AMR were the incore detectors and the area radiation monitors. The nonsafety-related incore detectors and the area radiation monitors do not perform a license renewal intended function per 10 CFR 54.4(a)(1), (2), or (3). Therefore, the incore detectors and the area radiation monitors are not included in the scope of the B.1.24 (XI.E2) AMP.
>
> A change will be made to LRA Section B.1.24 for clarification. The recommended change is as follows.
>
> The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized environments caused by heat, radiation and moisture (i.e., neutron flux monitoring instrumentation and high range radiation monitors); can be maintained consistent with the current license basis through the period of extended operation. Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provide sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.
>
> For sensitive instrumentation circuit cables that are disconnected during instrument calibration, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain

reflectometry) will occur at least every ten years, with the first test occurs before the period of extended operation. In accordance with corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the current licensing basis through the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.

The staff found the applicant's response acceptable because with the proposed LRA amendment and clarification described above, the scope of the Non-EQ Instrumentation Circuits Test Review Program is consistent with that in the GALL Report AMP XI.E2. The staff agreed with the applicant that incore detectors and area radiation monitors do not perform an intended function per 10 CFR 54.4(a)(1), (2), or (3) because they are non safety-related, their failure will not affect safety-function of safety-related components, and they are not credited in any regulated events under 10 CFR 54.4(a)(3). Therefore, they are not in the scope of the Non-EQ Instrumentation Circuits Test Review Program. The staff verified that in a letter dated December 18, 2007, the applicant amended LRA Section B.1.24 as described above.

Operating Experience. LRA Section B.1.24 states that the Non-EQ Instrumentation Circuits Test Review Program is a new program. When implementing this new program, the applicant will consider industry operating and plant-specific operating experience. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The applicant also stated that the Non-EQ Instrumentation Circuits Test Review program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant further stated that such operating experience assures management of the effects of aging so components continue to perform their intended functions consistent with the CLB through the period of extended operation.

SRP-LR Section A.1.2.3.10 provides guidance for staff review of operating experience. It states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. As stated above, the applicant stated that it will consider industry and plant-specific operating experience when implementing this program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.23 and A.3.1.23, the applicant provided the UFSAR supplement for the Non-EQ Instrumentation Circuits Test Review Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant committed to implement the Non-EQ Instrumentation Circuits Test Review Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits" (Commitment 16).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Non-EQ Instrumentation Circuits Test Review Program, the staff finds that all program elements are consistent with the GALL Report AMP XI.E2 program elements. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 Non-EQ Insulated Cables and Connections Program

Summary of Technical Information in the Application. LRA Section B.1.25 describes the Non-EQ Insulated Cables and Connections Program as a new program that will be consistent with the GALL Report AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The applicant stated that the Non-EQ Insulated Cables and Connections Program assures maintenance of the intended functions of insulated cables and connections exposed to adverse environments of heat, radiation, and moisture consistent with the CLB through the period of extended operation. An adverse environment is significantly more severe than the specified service condition for the insulated cable or connection. The applicant further stated that a representative sample of accessible insulated cables and connections within the scope of license renewal will be inspected visually for cable and connection jacket surface anomalies (*e.g.*, embrittlement, discoloration, cracking or surface contamination). The technical basis for sampling will be determined from EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments."

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Non-EQ Insulated Cables and Connections Program and basis documents to verify consistency with the GALL Report AMP XI.E1. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Non-EQ Insulated Cables and Connections Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.E1 except for the following area. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Under the program description for this AMP, the GALL Report states that this program can be thought as a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connection in the adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. In the program description of Non-EQ Insulated Cables and Connections Program, the applicant stated that a representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected. The staff requested the applicant to describe the technical basis for sampling and action taken if degradation was found on a representative sample (Audit Item 65). In a letter dated March 24, 2008, the applicant stated that this program addresses cables and connections under the premise that a large portion of cables and connections are accessible. This program sample consists of all accessible cables and connections in localized adverse environments. If an unacceptable condition or situation for cable or connection during this visual inspection, the corrective action process will be used for resolution. As part of the corrective action process, a determination will be made as to whether the same condition or situation is applicable to other cables and connections. The applicant will revise the LRA Sections B.1.25, A.2.1.24, and A.3.1.24, second paragraph as described below:

> A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environment.

The staff finds the applicant's response acceptable because the program will address cable and connections whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. This program is a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent all cables and connections in the adverse localized environment. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made to whether the same condition or situation is applicable to other cable or connections. The sample inspection is consistent with those in GALL AMP XI.E1. In a letter dated December 18, 2007, the applicant revised LRA Sections B.1.25, A.2.1.24, and A.3.1.24 as described above.

Operating Experience. LRA Section B.1.25 states that the Non-EQ Insulated Cables and Connections Program is a new program. When implementing this new program, the applicant will consider plant-specific and industrial operating experience as its basis. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The applicant also stated that the Non-EQ Insulated Cables and Connections Program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant further stated that such operating experience assures management of the effects of aging so components continue to perform their intended functions consistent with the CLB through the period of extended operation.

SRP-LR Section A.1.2.3.10 provides guidance for staff review of operating experience. It states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. As stated above, the applicant stated that it will consider industry and plant-specific operating experience when implementing this program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.24 and A.3.1.24, the applicant provided the UFSAR supplement for the Non-EQ Insulated Cables and Connections Program. The staff reviewed these sections and the amendments as described above and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant committed to implement the Non-EQ Insulated Cables and Connections Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" (Commitment 17).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion: On the basis of its audit and review of the applicant's Non-EQ Insulated Cables and Connections Program, the staff finds all program elements consistent with the GALL Report program elements. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 One-Time Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.27 describes the One-Time Inspection Program as a new program that will be consistent with GALL AMP XI.M32, "One-Time Inspection."

The One-Time Inspection Program confirms AMP effectiveness and the absence of aging effects. For structures and components that rely on AMPs, this program confirms that unacceptable degradation has not occurred and that component intended functions will be maintained during the period of extended operation. One-time inspections may be needed to address concerns about potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to rule it out completely or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect indeed has not occurred or the aging effect occurs so slowly as not to affect the component's or structure's intended function. A one-time inspection of the subject component or structure is appropriate for this confirmation.

The elements of the program include (a) determination of the sample size based on an assessment of fabrication materials, environment, plausible aging effects, and operating experience, (b) determination of the system or component inspection locations for the aging effect, (c) determination of the examination technique, including acceptance criteria effective for managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging effect. The program will confirm the absence of aging effects as described:

A one-time inspection activity confirms the effectiveness of:

- water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling have not occurred on system components managed by the programs
- the Oil Analysis Program by confirming that unacceptable cracking, loss of material, and fouling have not occurred on system components managed by the program
- the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material and fouling have not occurred on system components managed by the program

When a one-time inspection reveals evidence of an aging effect, routine evaluation of the inspection results develops appropriate corrective actions.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the One-Time Inspection Program and basis documents to verify consistency with the GALL Report AMP XI.M32. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the One-Time Inspection Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M32. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The applicant stated in the LRA that the sample size will provide 90 percent confidence that 90 percent of the population will not display degradation (90/90). The staff asked the applicant to justify the use of 90/90 for the sample size (Audit Item 71). By letter dated March 24, 2008, the applicant stated that it is following the guidelines in EPRI TR-107514, "Age Related Degradation Inspection Method and Demonstration," which describes methods used to inspect for age related degradation during the period of extended operation. This report recommends using the 90 percent confidence that 90 percent of the population will not display degradation. The justification for the 90/90 is that the locations selected for inspection are either the oldest components or are the locations most likely to be susceptible to degradation, so the true confidence is higher that 90 percent. The staff found this approach to be acceptable because biased sampling of the most susceptible locations should provide higher confidence than a 90/90 random sampling approach.

Operating Experience. LRA Section B.1.27 states that the One-Time Inspection Program is a new program. The applicant will consider industry operating experience when implementing this new program. The scopes of the inspections and inspection techniques are consistent with proven industry practices for managing the effects of aging. Plant-specific operating experience is consistent with the operating experience in the GALL Report program description.

The applicant also stated that the One-Time Inspection Program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant further stated that such operating experience assures management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.26 and A.3.1.26, the applicant provided the UFSAR supplement for the One-Time Inspection Program. By letter dated December 18, 2007, the applicant revised LRA Sections A.2.1.26, A.3.1.26, and B.1.27 to clarify that the "inspections will be nondestructive examinations (including visual, ultrasonic, or surface techniques)." Additionally, the applicant revised these sections for several one-time inspection activities that used the term "components" to replace the term "components" with the term "tanks, pump casings, piping, piping elements and components," as appropriate. By letter dated June 12, 2009, the applicant revised LRA Section A.2.1.26 to add one-time inspection activities for the internal surfaces of stainless steel piping, tubing, strainers, and valve bodies in the IP1 station air system exposed to condensation. The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement, as clarified, is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, "One-Time Inspection" (Commitment 19).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection Program, the staff finds all program elements consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 One-Time Inspection - Small Bore Piping Program

Summary of Technical Information in the Application. LRA Section B.1.28 describes the One-Time Inspection - Small Bore Piping Program as a new program that will be consistent with GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping."

LRA Section B.1.28 states that the One-Time Inspection - Small Bore Piping Program applies to small-bore ASME Code Class 1 piping less than 4 inches nominal pipe size (NPS), including pipe, fittings, and branch connections. The ASME Code does not require volumetric examination of Class 1 small-bore piping. The One-Time - Small Bore Piping Program will identify cracking by volumetric examinations.

The program will select a sample based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations. When a one-time inspection reveals evidence of an aging effect, evaluation of the inspection results will develop appropriate corrective actions.

In the GALL Report program description, GALL AMP XI.M35 includes piping less than or equal to NPS 4" with a reference to ASME Section XI, Table IWB-2500-1, Examination Category BJ; however, according to the ASME Code, a volumetric examination already is required for piping equal to 4-inch NPS. Consistent with the Code, GALL Report Item IV.C2-1 applies the One-Time Inspection of ASME Code Class 1 Small Bore Piping Program (XI.M35) only to Class 1 piping less than 4-inch NPS. On this basis, the applicant concludes that the intent of GALL Program XI.M35 is not to include 4-inch NPS pipe. Therefore, the One-Time Inspection - Small Bore Piping Program includes only small-bore Class 1 piping less than 4-inch NPS and is consistent with the GALL AMP.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the One-Time Inspection – Small Bore Piping Program and basis documents to verify consistency with the GALL Report AMP XI.M35. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the One-Time Inspection – Small Bore Piping Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M35. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During its review, the staff identified the following aspects of the applicant's program that needed additional clarification: (1) whether inspections performed on ASME Code Class 1 small bore piping to date have indicated any indications of cracking in the components, (2) the basis that will be used for selecting ASME Code Class 1 small bore piping for inspection during the period of extended operation, (3) whether ASME Code Class 1 piping that is 4-inch in diameter NPS is within the scope of the program, and (4) the acceptance criteria that will be used to evaluate relevant indication of cracking in these components.

During an onsite audit, the staff asked the applicant if the applicant had experienced cracking of ASME Class 1 small bore piping as a result of stress corrosion cracking or thermal and mechanical loading (Audit Item 73). By letter dated December 18, 2007, the applicant clarified that inspections to date at IP 2 and IP 3 have not revealed any indications of cracking in the ASME Code Class 1 small-bore piping components for the units. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the One-Time Inspection - Small Bore Piping Program is an acceptable AMP to credit for managing cracking in the ASME Code Class 1 small bore piping because: (1) the AMP is an acceptable AMP to credit for cases where no indications of cracking have been detected in the ASME Code Class 1 small bore piping components and (2) the applicant has not detected any indications of cracking in its ASME Code Class 1 piping as a result of the inspections that have been performed on these components. The staff's concern on this matter is resolved.

During the audit the staff asked the applicant if they were going to follow the guidance in Materials Reliability Program (MRP) -24 for identifying susceptible locations for inspection (Audit Item 74). By letter dated December 18, 2007, the applicant clarified that the program elements for the One-Time Inspection – Small Bore Piping program will be consistent with the corresponding program element recommendations in GALL AMP XI.M35. The applicant clarified that the program will include a sample selected based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations, and that MRP-24 (January 2001) or subsequent revisions of this industry guidance, will be followed for identifying susceptible locations for inspection. The staff noted that the applicant's response to Audit Item 74 was in conformance with the recommendation in the "monitoring and trending" program element in GALL AMP XI.M35, recommends that the sample size for the small bore piping inspections be based on a assessment of the susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations. The staff also noted that the applicant's response to Audit Item 74 was also in conformance with the recommendation in the "scope of program" program element in GALL AMP XI.M35 that EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 provides an acceptable basis for identifying those ASME Code Class 1 small bore piping locations that are most susceptible to cracking as a result of thermal stratification or turbulence.

Based on this review, the staff finds that the applicant has provided an acceptable basis for selecting those AMSE Code Class 1 small bore piping component for inspection because the applicant's basis is in conformance with the staff's recommendations for selecting susceptible components for inspection, as given in the "scope of program" program element in GALL AMP XI.M35. The staff also finds that the applicant has provided an acceptable basis for establishing the sample size of its AMSE Code Class 1 small bore piping component inspections because the applicant's basis is in conformance with the staff's recommendations for sample size, as given in the "monitoring and trending" program element in GALL AMP XI.M35. The staff's concern in Audit Item 74 is resolved.

During the audit, the staff asked the applicant if it intends to exclude 4" size from AMP B.1.28 from the scope of the applicant's One-Time Inspection - Small Bore Piping Program, and if so, whether this should be treated as an exception to GALL and a justification included in the LRA to establish exception to the GALL report (Audit Item 174). By letter dated December 18, 2007, the applicant clarified that the staff's AMR in GALL AMR Item IV.C2-1 identifies that the program is credited only for ASME Code Class 1 piping less than 4-inches NPS and that the Examination Categories B-F and B-J in Table IWB-2500-1 of the ASME Code, Section XI already require volumetric examinations for ASME Code Class 1 piping greater than or equal to 4-inches in diameter NPS. Thus, the applicant clarified that AMSE Code Class 1 piping equal to 4-inches NPS is not within the scope of the One-Time Inspection - Small Bore Piping Program. The staff verified that the requirements for volumetric examinations for ASME Code Class 1 piping greater than or equal to 4-inches in diameter NPS is already included within the scope of the applicant's Inservice Inspection Program (LRA AMP B.1.18). Based on this review, the staff finds that the applicant has provided an acceptable basis for excluding AMSE Code Class 1 piping equal to 4-inches NPS from the scope of the One-Time Inspection - Small Bore Piping Program because volumetric examinations of this ASME Code Class 1 pipe size is already included within the scope of the applicant's Inservice Inspection Program. The staff's concern in Audit Item 174 is resolved.

During the audit, the staff asked the applicant whether the applicant follows the applicable ASME Code, Section XI corrective action criteria in Paragraph IWB-3131 for flaw evaluation and supplemental examinations in Paragraph IWB-2430 for flaw indications exceeding their applicable flaw standard in Subarticle IWB-3400 (Audit Item 283). By letter dated December 18, 2007, the applicant confirmed that it follows the applicable ASME Code, Section XI corrective action criteria in Paragraph IWB-3131 for flaw evaluation and supplemental examinations in Paragraph IWB-2430 for any flaw indication in a small bore Class 1 piping components that exceeds its applicable flaw standard in Subarticle IWB-3400. The staff noted that the volumetric examinations recommended in GALL AMP XI.M35 for small bore Class 1 piping components are not ASME Code, Section XI mandated examinations, and therefore, go beyond the current 10 CFR 50.55a mandated inservice inspection (ISI) requirements for these types of components in ASME Code, Section XI Table IWB-2500-1. As such, the applicant is not obligated to using the stated ASME Code, Section XI-based correction actions for its non-mandatory, LRA-recommended one-time volumetric examinations. The staff noted, however, that the applicant credited these ASME Code, Section XI-based corrective action provisions for any flaw indication in a small bore Class 1 piping components that exceeds its applicable flaw standard in Subarticle IWB-3400. Thus, the staff finds that the applicant has provided an acceptable basis for corrective actions of any non-conforming indications because the applicant is applying the conservative Code-based corrective actions to any non-conforming indication that is detected as a result of the non-mandatory, LRA-recommended one-time volumetric examinations that will be performed on these small bore ASME Code Class 1 piping components. The staff's concern in Audit Item 283 is resolved.

Based on the review of this AMP and the applicant's responses to the audit questions, the staff finds this program acceptable because the staff has verified that the program elements for the applicant's One-Time Inspection – Small Bore Piping Program are in conformance with the staff's aging management criteria that are provided in the program elements of GALL AMP XI.M35, and because the applicant will implement this program consistent with GALL AMP XI.M35 recommendations.

Operating Experience. LRA Section B.1.28 states that the One-Time Inspection - Small Bore Piping Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

In its response to Audit Item 73, the applicant indicated that previous non-volumetric inservice inspections performed on the small bore ASME Code Class 1 piping components did not reveal any indication of cracking in the piping components. In addition, the staff noted that the applicant indicated that there are not any small bore ASME Code Class 1 socket welds at IP2 and IP3 that have been identified as critical welds from a risk-informed inservice inspection (RI-ISI) program perspective. Therefore, small bore ASME Code Class 1 socket welds are not included within the scope of the applicant's One-Time Inspection - Small Bore Piping Program. The staff has confirmed that the applicant instead credits the surface examination requirements and visual examination requirements in the applicant's Inservice Inspection Program as the basis for inspecting the applicant's small bore ASME Code Class 1 socket welds. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the One-Time Inspection - Small Bore Piping Program may be used to verify whether cracking is occurring in the applicant's ASME Code Class 1 piping components during the period of extended operation because the applicant has not detected any indications of cracking as a result of the non-volumetric examinations that were performed on these components through implementation of the applicant's Inservice Inspection Program, and because the IP2 and IP3 designs do not include any critical small bore ASME Code Class 1 socket weld locations that are considered to be critical risk-informed locations under the applicant's RI-ISI program. Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.27 and A.3.1.27, the applicant provided the UFSAR supplement for the One-Time Inspection - Small Bore Piping Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, "One-Time Inspection – Small Bore Piping" (Commitment 20).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection - Small Bore Piping Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.11 Reactor Head Closure Studs Program

Summary of Technical Information in the Application. LRA Section B.1.30 describes the existing Reactor Head Closure Studs Program as consistent with GALL AMP XI.M3, "Reactor Head Closure Studs."

The Reactor Head Closure Studs Program includes inservice inspection (ISI) in compliance with the requirements of ASME Section XI, Subsection IWB, and preventive measures (e.g., rust inhibitors, stable lubricants, appropriate materials) to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings.

The GALL Report program, Section XI.M3, Reactor Head Closure Studs, is based on ASME Code 2001 Edition including the 2002 and 2003 Addenda. The ISI program is based on ASME Code 1989 Edition, no addenda, with inspection of reactor head closure studs based on the 1998 Edition through the 2000 Addenda. The 1998 Edition through the 2000 Addenda allow surface or volumetric examination when closure studs are removed. This is consistent with the requirements of GALL Report, Section XI.M3. Therefore, use of different ASME Code editions for this program is not an exception to the GALL Report.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Reactor Head Closure Studs Program and basis documents to verify consistency with the GALL Report AMP XI.M3. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Reactor Head Closure Studs Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M3. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff confirmed that the existing Reactor Head Closure Studs Program at IP is part of the applicant's ISI program under ASME Code, Section XI, Subsection IWB, Examination Category B-G-1. The staff also confirmed that the program includes the preventive measures (e.g., rust inhibitors, stable lubricants, appropriate materials) that are recommended in NRC RG 1.65 to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings, and that these activities are performed under several plant-specific programs or activities. The staff verified that these programs and activities include measures to ensure conformance with closure stud material specifications during procurement, metal plating activities to prevent corrosion or hydrogen embrittlement, use of manganese phosphate or other acceptable surface treatment and stable lubricant during service, and implementation of the ISI examinations, which mandated by the ASME Code, Section XI, Examination B-G-1 requirements. The staff found this to be acceptable because it is in compliance with the requirements for reactor vessel closure stud components in the ASME Code, Section XI and because it is in conformance with the program element recommendations in GALL AMP XI.M3.

The staff notes that this program is based on the ASME Section XI Code Edition 1998, up to 2000 addenda, although the applicant's Inservice Inspection Program is based on 1989 Edition of the Code. According to the 1998 Code Edition (Code Item B6.30), the program allows surface or volumetric examination when closure studs are removed, which is not consistent with the requirements of GALL Report, Section XI.M3. The GALL Report program element "detection of aging effects" states that the Code requires "both surface and volumetric examination of studs" when removed. During an onsite audit, the staff asked Entergy to clarify why this is not an exception to the GALL recommendations (Audit Item 82).

By letter dated March 24, 2008, the applicant stated that GALL AMP XI.M3 also references ASME Section XI 2001 edition including the 2002 and 2003 Addenda, which allows surface or volumetric examination when closure studs are removed. The applicant also clarified that the inservice inspection requirements in the 1998 Edition of the ASME Code, Section XI, inclusive of the 2000 Addenda require either a surface examination or volumetric examination of the closure studs when they are removed. This is the same examination requirement for these studs that is provided in the 2001 Edition of ASME Code, Section XI, inclusive of the 2003 Addenda referenced in GALL AMP XI.M3. The staff reviewed the two Code editions and verified that the examination requirements for reactor vessel closure studs in the 1998 Edition of the ASME Code, Section XI (inclusive of the 2000 Addenda) is the same as that required for the studs in the 2001 Edition of the ASME Code, Section XI (inclusive of the 2003 Addenda). The staff also noted that, in the applicant's letter of June 11, 2008, the applicant clarified that the updated Code of Record for IP2 is the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda, and that the Code of Record for IP3 is the 1989 Edition of the ASME Code, Section XI. The staff verified that the use of the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda is consistent with the Code editions referenced for use in GALL AMP XI.M3. The staff also confirmed that the inservice inspection bases for the reactor vessel closure studs in the 1998 Edition of the ASME Code, Section XI, inclusive of the 2000 Addenda, are the same as, and are consistent with, the inservice inspection bases for the closure studs in the 2001 Edition of the ASME Code, inclusive of the 2003 Addenda, as referenced for use in GALL AMP XI.M3. Therefore, based on this review the staff finds that the inspection bases for the reactor vessel closure studs at IP2 and IP3 are consistent with the Code requirements referenced in GALL AMP XI.M3 and are acceptable.

During an onsite audit, the staff reviewed the following four aspects of the RG 1.65 recommendations: material specification during procurement, avoiding the use of metal-plated stud bolting to prevent corrosion or hydrogen embrittlement, use of manganese phosphate or other acceptable surface treatments and stable lubricants during service, and ISI examination. During the audit, Entergy provided access to plant documents that addressed the RG 1.65 recommendations. The staff determined that the procurement and material specifications aspects of the RG 1.65 recommendations are followed as evidenced in purchase order documents. The staff determined that the preventive measures recommended in the RG with respect to lubricants, rust inhibitors, etc., are not applicable to IP since all bolts are plasma bonded and since this fabrication method does not involve the use of lubricants. The staff noted that the applicant implements the inspections of its reactor vessel closure studs in accordance with the applicant's Inservice Inspection Program (refer to AMP B.1.18) and the ASME Code, Section XI Examination Category B-G-1 requirements for reactor vessel closure assembly components. The staff finds this to be acceptable because it is in compliance with the requirements of 10 CFR 50.55a and the ASME Code, Section XI and because it is in conformance with the inspection recommendations for reactor vessel closure studs in GALL AMP XI.M3.

The staff also notes that this AMP, as recommended in RG 1.65, is applicable to closure studs and nuts constructed from materials with a maximum tensile strength limited to less than 170 ksi (1,170 MPa). During discussions with the applicant during the audit, Entergy stated that, for IP2, results of testing from available test reports for the original and refurbished reactor head closure stud and nut material showed a maximum tensile strength value < 170 ksi (1,170 MPa). However, for IP3, the original and refurbished reactor head closure stud and nut materials showed a maximum tensile strength value of 174 ksi (1,200 MPa), which was above the value in RG 1.65. The applicant also stated that the slight deviation above 170 ksi (1,170 MPa) shown in the test results does not significantly increase the material's potential for embrittlement and stress corrosion cracking. After reviewing the tensile testing data on bolt materials for IP3, the staff determined that the test results relating to several tests both for original and replaced studs are made out of ASME SA-540 B23/24 materials with an average tensile strength less than 170 ksi (1,170 MPa). The staff determined that, for IP3, only a few of the test results for the original bolt materials exceeded the 170 ksi (1,170 MPa) limit, with a maximum of 174 ksi (1,200 MPa). The staff verified that, in order to address the issue with high tensile strength RV studs, the applicant has appropriately identified cracking as an applicable aging effect requiring management for the IP2 and IP3 reactor vessel closure assembly studs, nuts and washers, and that the applicant credits the inservice inspections that are within the scope of this AMP and are implemented in accordance with the applicant's Inservice Inspection Program, Examination Category B-G-1 requirements as the basis for managing cracking in these components. The staff finds this to be acceptable because it is in accordance with the "parameters monitored or inspected" and "detection of aging effects" program elements in GALL AMP XI.M3.

Since the program basis documents for the Reactor Head Closure Studs Program is based on the ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 requirements and the recommendations in NRC RG 1.65, the staff finds that the applicant's Reactor Vessel Closure Studs Program is consistent with recommended program element criteria in GALL AMP XI.M3 and is acceptable.

Operating Experience. LRA Section B.1.30 states that ISI-IWB examinations were conducted at IP2 and IP3 during 2004 and 2005. Results found to be outside of acceptable limits were repaired, replaced, or evaluated in accordance with ASME Section XI requirements. Detection of degradation and corrective action prior to loss of intended function assure program effectiveness in managing aging effects.

The applicant also stated that an ISI program self-assessment was completed in October 2004. Review of the scope for refueling outage 2R16 (2004) and refueling outage 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment for IP2 in March 2006 ensured that all inspection activities required to close out the third 10-year ISI interval were scheduled for refueling outage 2R17. The applicant concluded that confirmation of compliance with program requirements assures continued effective management of loss of component material. QA surveillances in 2005 and 2006 revealed no issues or findings that could impact program effectiveness.

The staff reviewed the QA self-assessment documents for the applicant's Inservice Inspection Program for IP2 and IP3 and found that QA self-assessments reported that the applicant's Inservice Inspection Program appropriately identified and took corrective measures on the inspection findings. The staff noted that there are several deficiencies identified in these reports and verified that the applicant has taken appropriate corrective actions to address the deficiencies that were identified in these reports. Based on this aspect of the applicant's program, the staff did not identify any issues with the applicant's program that would impact the effectiveness of the Reactor Head Closure Studs Program in managing the aging effects that are applicable to the RV closure stud assembly components.

Therefore, based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.29 and A.3.1.29, the applicant provided the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Reactor Head Closure Studs Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.12 Reactor Vessel Head Penetration Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.31 describes the existing Reactor Vessel Head Penetration Inspection Program as consistent with GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors."

LRA Section B.1.31 states that the Reactor Vessel Head Penetration Inspection Program manages primary water stress corrosion cracking (PWSCC) of nickel-based alloy reactor vessel head penetrations exposed to borated water to maintain pressure boundary function. This program was developed in response to NRC Order EA-03-009. The applicant uses the ASME Section XI, Subsection IWB Inservice Inspection and Water Chemistry Control Programs with this program to manage cracking of the reactor vessel head penetrations. A combination of bare metal visual examination (external surface of head) and non-visual examination (underside of head) techniques detects cracking. Procedures are developed for reactor vessel head bare metal inspections and calculations of plant susceptibility ranking. Entergy will continue to implement commitments to (1) NRC orders, bulletins, and GLs on nickel alloys and (2) staff-accepted industry guidelines.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Reactor Vessel Head Penetration Inspection Program and basis documents to verify consistency with the GALL Report AMP XI.M11A. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Reactor Vessel Head Penetration Inspection Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M11A. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During audit, the staff confirmed that all 97 penetrations at IP2 and all 78 penetrations at IP3 reactor vessel heads and associated J-groove welds, and the adjoining upper RV closure heads are within the scope of this program.

The staff noted that this program was developed based on the commitments that the applicant made in response to the staff's augmented inspection and flaw evaluation requirements that were issued in NRC Order EA-03-009, as amended in the applicant's response to the staff's augmented inspection and flaw evaluation requirements that were issued in First Revised Order EA-03-009 (henceforth referred to the Order as Amended). The staff verified the applicant's commitments made in the applicant's responses to the Order as Amended are within the scope of the program, as provided in the following Entergy Letters:

- Entergy Letter No. NL-03-037, dated March 3, 2003 (ADAMS Accession number ML030650884)
- Entergy Letter No. NL-04-026, dated March 11, 2004 (ADAMS Accession number ML041610278)

The staff noted that the applicant credits its Water Chemistry Control Program – Primary and Secondary in conjunction with this program to manage cracking of the reactor vessel head penetration nozzles and their associated nickel alloy nozzle-to-vessel penetration welds. The staff finds this to be acceptable because it is consistent with the AMRs that invoke this program for aging management, and because this in accordance with the "preventive actions" program element criteria that are recommended in GALL Report AMP XI.M11A.

The staff noted that the program uses a combination of bare metal visual examination (external surface of head) and non-visual examination (underside of head) techniques as the bases for managing cracking that is postulated to occur in these nozzle components. The staff finds this to be acceptable because it is in conformance with the "detection of aging effects" program element in GALL Report AMP XI.M11A.

The staff noted and verified that the applicant has established plant procedures that govern the applicant's augmented bare metal visual inservice inspection activities for the IP2 and IP3 upper reactor vessel RV closure heads and the non-visual non-destructive examination (non-visual NDE) methods (i.e., either ultrasonic testing (UT) or eddy current testing (ECT)) for the nickel alloy upper RV closure head penetration nozzles and their associated nickel alloy penetration welds. The staff also noted that the applicant has established plant procedures for calculating the susceptibility rankings of the IP2 and IP3 upper RV closure head penetration nozzles in accordance with susceptibility ranking calculation requirements of the Order as Amended.

By letter dated March 24, 2008, in response to an audit question (Audit Item 83), the applicant clarified that, as of the last refueling outage for IP2 (Spring 2006), the upper RV closure head penetration nozzles at IP2 are categorized as a moderate susceptibility category penetration nozzles, as calculated using the staff's required susceptibility calculation equations that are given in the Order as Amended, and as of the last refueling outage for IP3 (Spring 2007), the upper RV closure head penetration nozzles at IP3 are categorized as a high susceptibility category penetration nozzles, as calculated using the same required susceptibility calculation equations. The staff finds this to be acceptable because it is in compliance with the requirements in the Order as amended, and because this is consistent with the "detection of aging effects" and "monitoring and trending" program elements in GALL Report AMP XI.M11A.

The staff verified that the applicant has established an augmented inspection program plan for these Class 1 penetration nozzles that addresses all of the bare metal visual and non-visual NDE inspection requirements in the Order as amended for the upper RV closure head penetrations, as ranked for the moderate susceptibility ranking for IP2 and the high susceptibility ranking for IP3, and approved for relaxation from the requirements of the Order as Amended in the following NRC safety evaluations:

- Safety evaluation for IP2 dated February 27, 2006, granting a reduced vertical inspection coverage for the RV closure head penetration nozzles based on the inaccessibility of the threaded non-pressure boundary portions of the nozzles
- Safety evaluation for IP2 dated October 15, 2004, granting a reduced inspection coverage (to 95% coverage) for bare metal examinations required to be performed on the IP2 upper RV closure head
- Safety evaluation for IP3 dated April 4, 2005, granting a reduced vertical inspection

coverage for the RV closure head penetration nozzles based on the inaccessibility of the threaded non-pressure boundary portions of the nozzles

- Safety evaluation for IP3 dated March 18, 2005, granting a reduced inspection coverage (to 95% coverage) for bare metal examinations required to be performed on the IP3 upper RV closure head

The staff finds that the inspection bases granted in these safety evaluations are acceptable because they are in conformance with the required inspection bases that are defined in the "detection of aging effects" and "monitoring and trending" program elements in GALL Report AMP XI.M11A.

In the same response (Audit Item 83), Entergy also stated that the Boric Acid Corrosion Prevention Program (B.1.5) complements the Reactor Vessel Head Penetration Inspection Program by performing visual inspection of the reactor vessel head at locations specified by IP2-specific and IP3-specific plant procedures. The staff noted that these procedures provide general guidance for performing the system walkdowns and bare metal visual examinations of both the IP2 and IP3 upper RV closure heads and other ASME Code Class 1 components for evidence of boric acid leakage, boric acid residues, or signs of corrosion.

The staff verified that the applicant coordinates the activities with reactor vessel disassembly and the inspections that are required by Order as Amended, in accordance with the applicant's implementing procedures and outage scheduling.

Based on its review of the applicant's augmented inspection program plan for upper RV closure heads and its associated penetrations nozzles, the staff verified that the applicant credits the program's UT and ECT examination methods for the detection of cracking of nozzle penetrations and their nickel alloy penetration welds. The staff also verified that the applicant credits its bare metal visual inspections of the upper RV heads with the detection of evidence of reactor coolant leakage from the upper RV closure head penetration nozzles, boric acid residues that precipitate out on the upper RV head or adjacent components, or corrosion products that result from rusting of the low-alloy steel materials used to fabricate the RV heads or shells. The staff finds that this is acceptable because the inspection methods that are credited for examination and the parameters that these inspections methods are credited for are consistent with the staff's recommended criteria that are provided in the "parameters monitored/inspected" and "detection of aging effects" program elements in GALL Report AMP XI.M11A.

Based on this review, the staff finds that the applicant Reactor Vessel Head Penetration Inspection Program is acceptable because the program is designed to be in compliance with the requirements of the Order as Amended and because the staff has verified that the program elements for the program are in conformance with the program element criteria that are recommended in GALL Report AMP XI.M11A.

Operating Experience. LRA Section B.1.31 states that bare metal visual examination of no less than 95 percent of the IP2 reactor vessel head surface and 360 degrees around each head penetration nozzle completed in November 2004 (refueling outage 2R16) consistently with the requirements of NRC Order EA-03-009 and approved relaxation request found no indications of reactor vessel head degradation or leakage due to cracking.

The applicant also stated that bare metal visual examination of no less than 95 percent of the IP3 reactor vessel head surface and 360 degrees around each head penetration nozzle completed during March 2005 (refueling outage 3R13), consistent with the requirements of NRC Order EA-03-009 and approved relaxation requests, found no indications of reactor vessel head degradation or leakage due to cracking. A QA surveillance of these inspections found all regulatory requirements met.

Further, the applicant stated that the most recent inspection of the IP2 reactor vessel head penetrations completed in May 2006 (refueling outage 2R17) used a procedure written from lessons learned during the refueling outage 2R16 and refueling outage 3R13 inspections. The results of this refueling outage 2R17 inspection were satisfactory. This inspection noted that bare metal areas reviewed had significant improvement in the cleanliness in the base metal and annulus around the penetrations. A QA surveillance of these inspections found all regulatory requirements met. A self-assessment of the inspection process noted improvements that should be made before future use of the process. Corrective actions implemented these process improvements. Absence of cracking with continuous improvement of material condition assures program effectiveness in managing aging effects. Use of recent operating experience and industry guidance in the development of site-wide procedures with site QA oversight and continuous process improvement assures continued program effectiveness in managing aging effects for passive components.

The staff verified that the applicant's Reactor Vessel Head Penetration Inspection Program was developed and is being implemented to address the cracking and boric acid leakage events that have been identified and discussed in the Order as Amended, and in NRC Bulletins 2002-01 and 2002-02, that were issued prior to the Order as Amended.

The staff verified that the latest augmented inspection reports for the IP2 and IP3 upper RV closure head and its penetration nozzles are given in the following inspection reports that were required to be reported in accordance with the requirements of the Order as Amended:

- Entergy Letter No. NL-05-001 for IP2, dated January 17, 2005 (ML050260199) – reporting bare metal visual examination inspection results performed on the IP2 head.
- Entergy Letter No. NL-06-064 for IP2, dated July 12, 2006 (ML062050686) – reporting non-visual NDE inspections on all 97 upper RV closure head penetration nozzles using UT and ECT.
- Entergy Letter No. NL-05-044 for IP3, dated May 31, 2005 (ML051590104) – reporting bare metal visual examination inspection results performed on the IP3 head.
- Entergy Letter No. NL-06-064 for IP3, dated May 22, 2007 (ML071510185) – reporting non-visual NDE inspections on all 78 upper RV closure head penetration nozzles using both UT and ECT).

The staff verified that in the letters, Entergy reported that the inspections did not identify any indications of reactor coolant pressure boundary leakage from the IP2 and IP3 upper RV closure head penetration nozzles or evidence of cracking in these nozzles or their structural nickel-alloy welds. By letter dated January 17, 2005, the applicant did report some Conoseal leakage at IP2 and IP3. The staff's evaluation on the applicant's steps to correct Conoseal leakage is given in SER Section 3.0.3.1.1. Based on this review, the staff also finds that the applicant has been taking appropriate steps to determine whether there is any site-specific operating experience on cracking of the IP2 and IP3 upper RV closure head penetration nozzles or on reactor coolant leakage from the nozzles onto the upper RV closure head or adjacent Class 1 components.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10 because the staff has verified that applicant is currently performing the mandatory examinations of the IP2 and IP3 upper RV closure heads and their penetration nozzles in order to address the generic operating experience discussed in the Order as Amended. Based on this review, the staff finds this program element to be acceptable.

UFSAR Supplement. In LRA Sections A.2.1.30 and A.3.1.30, the applicant provided the UFSAR supplement for the Reactor Vessel Head Penetration Inspection Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Reactor Vessel Head Penetration Inspection Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.13 Selective Leaching Program

Summary of Technical Information in the Application. LRA Section B.1.33 describes the Selective Leaching Program as a new program that will be consistent with GALL AMP XI.M33, "Selective Leaching of Materials."

In the LRA, the applicant stated that the Selective Leaching Program will ensure the integrity of components made of gray cast iron, bronze, brass, and other alloys exposed to raw water, treated water, or groundwater that may lead to selective leaching. The program will include a one-time visual inspection, hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching has occurred and whether the process will affect component ability to perform intended functions through the period of extended operation.

By letter dated March 24, 2008, the applicant amended the program description to add the following:

> The selected set or representative sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience

degradation (90/90). Each group of components with the same material-environment combination is considered a separate population.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Selective Leaching Program to verify consistency with GALL AMP XI.M33. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Selective Leaching Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M33. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During the audit, the staff reviewed the applicant's program evaluation document and confirmed that the program scope includes all systems that could be susceptible to selective leaching. These include cast iron, brass, bronze, or aluminum-bronze and exposed to raw water, treated water, or groundwater environments. Systems that have this combination of material and environment include susceptible components that include piping, valve bodies and bonnets, pump casings, and heat exchanger (HX) components.

Operating Experience. LRA Section B.1.33 states that the Selective Leaching Program is a new program. When implementing this new program, the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The program is based on the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of aging effects so components continue to perform intended functions consistent with the CLB through the period of extend operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.32 and A.3.1.32, the applicant provided the UFSAR supplement for the Selective Leaching Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M33, "Selective Leaching of Materials" (Commitment 23).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Selective Leaching Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.14 Service Water Integrity Program

Summary of Technical Information in the Application. LRA Section B.1.34 describes the existing Service Water Integrity Program as consistent with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

The Service Water Integrity Program implements the recommendations of GL 89-13 for managing the effects of aging on the service water (SW) system, through the period of extended operation. The program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by SW. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in SW components.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Service Water Integrity Program to verify consistency with GALL AMP XI.M20. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Service Water Integrity Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M20. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.34 states that in July 2003 a peer assessment of the IP3 SW program conducted by EPRI found some areas for improvement. Corrective actions included changes to chlorination practices and evaluation of new software tools for heat exchanger performance analysis. Assessment of practices by offsite review groups and appropriate corrective action assure continued program effectiveness in managing aging effects for passive components.

The applicant stated that self-assessments of the IP2 and IP3 ultimate heat sink (GL 89-13 Program) in April 2004 and June 2005 focused on adequate maintenance of ultimate heat sink subcomponents and their operation within the plant design basis. The applicant concluded that detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing loss of component material.

In the LRA, the applicant noted that in December 2005, the staff completed an ultimate heat sink performance review at IP2 to verify that Entergy continually monitored performance of the instrument air closed cooling water heat exchangers and to detect potential deficiencies which could mask degraded performance. The staff reviewed the design basis documents and final safety analysis report for whether testing acceptance criteria were appropriate. The staff also reviewed the latest inspection reports for the heat exchangers and evaluated the results of eddy current testing for use of appropriate tube plugging criteria. In addition, the staff verified whether Entergy had maintained its commitments to GL 89-13 on heat exchanger inspection and testing and made no findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

As part of the ultimate heat sink performance review at IP3 in 2005, the staff observed the condition of a component cooling water (CCW) heat exchanger after it had been opened for periodic inspection and cleaning and reviewed preventive maintenance of this safety-related heat exchanger for adequacy in minimizing the effects of biofouling on its performance. The staff visually examined the heat exchanger when it was first opened to assess the adequacy of Entergy's periodic cleaning to avoid excessive fouling, compared the as-found eddy current testing results to previous testing data, and made no significant findings. Reviews of program specifics prove program effectiveness in managing loss of component material.

The applicant also noted that in June 2006, the staff completed an ultimate heat sink performance review at IP3 for whether Entergy had used the periodic maintenance method outlined in EPRI NP-7552, "Heat Exchanger Performance Monitoring Guidelines," for the IP3 emergency diesel generator (EDG) lube oil coolers. The staff reviewed the results of the last inspections and eddy current tests for each of the lube oil coolers and made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

Further, the applicant stated, in June 2006, the staff completed at IP2 an ultimate heat sink performance review which included the CCW heat exchangers and the EDG jacket water and lube oil heat exchangers. The staff reviewed documents for whether Entergy had detected and corrected common cause heat sink performance problems with the potential to increase risk. The staff also reviewed records for whether Entergy had examined potential macro fouling (silt, debris, etc.) and biofouling issues closely. To ensure adequate implementation of Generic Letter 89-13, the staff reviewed Entergy's inspection, cleaning, and eddy current testing methods and frequency with the responsible system engineers. The staff compared surveillance test and inspection data, including as-found conditions and eddy current summary sheets, to the established acceptance criteria to verify whether the results were acceptable and the system heat exchanger operation was consistent with design. The staff reviewed heat exchanger design-basis values and assumptions, plugging limit calculations, and vendor information to verify whether they were incorporated into the heat exchanger inspection and maintenance procedures. The staff reviewed a sample of condition reports for the CCW and EDG heat exchangers and the SWS for whether Entergy had detected, characterized, and corrected problems related to these systems and components appropriately and made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

The staff's review of Appendix B of the LRA and of the applicant's basis document found them to conclude that the Service Water Integrity Program has been effective in managing those aging effects for which it is credited. The staff noted, however, that this conclusion is based on the results of one peer assessment, one self-assessment and five NRC inspections of the GL 89-13 program. Since the guidelines of GL 89-13 are directed at ensuring the performance of safety-related systems and components exposed to SW, it is not clear how the results of inspections performed under the GL 89-13 program could be used to confirm the absence of aging effects in nonsafety-related components within scope for license renewal. In addition, NRC inspections of the GL 89-13 program are based on a limited sample of safety-related components. For example, NRC Inspection Procedure IP 93810 (Service Water System Operational Performance Inspection) specifically states that the selection of SW system components and systems should consider those that have been dominant contributors to the SW system operational risk at the plant or similar plants.

In RAI AUX-2, dated May 7, 2008, the staff requested the applicant to clarify whether the Service Water Integrity Program is credited for aging management of the nonsafety-related components of the SW system that are within scope for license renewal, and if so, to provide evidence for the conclusion presented in the LRA, that this AMP is effective in managing age-related degradation. If this AMP is not credited, the staff requested the applicant to identify the AMP(s) that are credited for aging management of the nonsafety-related components of the SW system that are within scope for license renewal and to provide the basis for concluding that these programs have been or will be effective for managing aging during the license renewal period.

By letter dated June 5, 2008, the applicant provided the following response:

> The Service Water Integrity Program is credited for managing the effects of aging on components as listed in LRA Section 3 tables regardless of safety classification.
>
> The materials of construction and operating environment for components and piping in nonsafety-related and safety-related portions of the SWS are identical. Therefore, the aging effects managed by the Service Water Integrity Program are identical.
>
> As stated in LRA Section B.1.34, the Service Water Integrity Program is consistent with NUREG-1801, Section XI.M20, Open Cycle Cooling Water System and includes activities that apply to both safety-related and nonsafety-related components described below.
>
> 1. Component inspections for erosion, corrosion, and biofouling. Results of these inspections have been used to determine the corrective actions required to preclude recurrence of unacceptable conditions, as described in LRA Section B.0.3. All components in the SWS [service water system] flowpath are within the scope of such corrective actions regardless of safety classification.
>
> 2. Safety-related heat exchangers in the program are tested to verify heat transfer capabilities. Nonsafety-related heat exchangers cooled by service water are periodically inspected. These inspections are sufficient to manage aging effects since there is no license renewal component intended function of heat transfer.
>
> 3. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are applied to all components in the SWS flowpath regardless of safety classification. In

this manner, the program remains effective for managing aging effects for all components in the SWS.

4. GL 89-13 inspections are performed on nonsafety-related piping. For example, during [refueling outage] 2R18 in March and April 2008, approximately 10% of the scheduled GL 89-13 program volumetric weld examinations were conducted on nonsafety-related SWS piping welds, and approximately 25% of the scheduled GL 89-13 program visual inspections were conducted on nonsafety-related SWS piping. Scope expansion for indications found by GL 89-13 inspections of nonsafety-related piping is based on consideration of location, severity, materials, previous inspection history, and other relevant factors.

5. System walkdowns apply to both SWS safety-related and nonsafety-related components.

Considering that activities under the Service Water Integrity Program apply to both safety-related and nonsafety-related components, the program effectiveness conclusions of recent peer and self assessments as well as NRC inspections described in the operating experience section are applicable to all components crediting the program for aging management.

The staff noted that the scope of GALL AMP XI.M20, "Open-Cycle Cooling Water System," is applicable to safety-related service water system components that are tied to the ultimate heat sink for the facility. The applicant's response clarifies that it is conservatively applying its Service Water Integrity Program to both the safety-related and nonsafety-related components that are exposed to the service water environment. Thus, based on the staff's review of the Service Water Integrity Program, as amended in the applicant's response to RAI AUX-2, the staff finds the applicant has provided an acceptable basis for managing aging effects in the nonsafety-related service water system components consistent with the program elements in GALL AMP XI.M20. The staff's concern in RAI AUX-2 is resolved.

<u>UFSAR Supplement</u>. In LRA Sections A.2.1.33 and A.3.1.33, the applicant provided the UFSAR supplement for the Service Water Integrity Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Service Water Integrity Program, the staff finds all program elements consistent with the GALL Report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.15 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.37 describes the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program as a new program that

will be consistent with GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."

LRA Section B.1.37 states that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program augments the inspection of reactor coolant system components in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. The augmented inspection detects the effects of loss of fracture toughness due to thermal aging embrittlement of CASS components. This AMP determines the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. The program manages aging through either enhanced volumetric examination or flaw tolerance evaluation. Additional inspections or evaluations to demonstrate adequate material fracture toughness are not required for components that are not susceptible to thermal aging embrittlement. In the staff's letter from Christopher Grimes, NRC, to Douglas Walters, NEI, the staff provided its basis for establishing that CASS pump casings and valve bodies do not need to be screened for thermal aging embrittlement. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings and valve bodies.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program to verify consistency with GALL AMP XI.M12. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M12. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.37 states that the Thermal Aging Embrittlement of CASS Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program is based on the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.36 and A.3.1.36, the applicant provided the UFSAR supplement for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" (Commitment 26).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program, the staff finds that all program elements presented in the program basis documents are consistent with the GALL report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.16 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program

Summary of Technical Information in the Application. LRA Section B.1.38 describes the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program as a new program that will be consistent with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)."

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program augments the reactor vessel internals visual inspection in accordance with the ASME Code, Section XI, Subsection IWB. This augmented inspection manages the effects of loss of fracture toughness due to thermal aging and neutron embrittlement of CASS components. This AMP determines the susceptibility of CASS components to thermal aging or neutron irradiation (neutron fluence) embrittlement based on casting method, molybdenum content, operating temperature, and percent ferrite. For each potentially susceptible component, aging management is through either a component-specific evaluation or a supplemental examination of the affected component as part of the ISI program during the license renewal term.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program to verify consistency with GALL AMP XI.M13. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M13. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.38 states that the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is based on the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.37 and A.3.1.37, the applicant provided the UFSAR supplement for the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)" (Commitment 27).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program, the staff finds all program elements consistent with the GALL report. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 Programs Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant stated that the following programs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Aboveground Steel Tanks Program
- Bolting Integrity Program
- Boraflex Monitoring Program
- Diesel Fuel Monitoring Program

- External Surfaces Monitoring Program
- Fatigue Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Flux Thimble Tube Inspection Program
- Masonry Wall Program
- Metal-Enclosed Bus Inspection Program
- Oil Analysis Program
- Reactor Vessel Surveillance Program
- Steam Generator Integrity Program
- Structures Monitoring Program
- Water Chemistry Control - Closed Cooling Water Program
- Water Chemistry Control - Primary and Secondary Program

For programs that the applicant claimed are consistent with the GALL Report, with exception(s) and/or enhancement(s), the staff performed an audit and review 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/or enhancement(s) to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 Aboveground Steel Tanks Program

Summary of Technical Information in the Application. LRA Section B.1.1 describes the existing Aboveground Steel Tanks Program as consistent with GALL AMP XI.M29, "Aboveground Steel Tanks," with enhancements.

The Aboveground Steel Tanks Program manages loss of material from external surfaces of aboveground carbon steel tanks by periodic visual inspection of external surfaces and thickness measurement of locations inaccessible for visual inspection.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Aboveground Steel Tanks Program to verify consistency with GALL AMP XI.M29. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Aboveground Steel Tanks Program elements "scope of program," "preventive actions," and "parameters monitored or inspected," are consistent with the corresponding elements in GALL AMP XI.M29. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements "detection of aging effects," and "acceptance criteria," prior to the period of extended operation: "Revise applicable procedures to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank (IP2), and the fire water tanks once during the first ten years of the period of extended operation."

The staff finds this enhancement acceptable because it establishes the thickness measurements for the bottom surfaces of these tanks as recommended in the GALL Report.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "monitoring and trending" prior to the period of extended operation: "Revise applicable procedures to require trending of thickness measurements when material loss is detected."

The staff finds this enhancement acceptable because it establishes the practice of trending of thickness measurements as recommended in the GALL Report.

Operating Experience. LRA Section B.1.1 states that visual inspections detected corrosion on the top of the IP3 condensate storage tank in 2003 and 2005 and on the IP2 condensate storage tank in 2004. Corrective actions cleaned and repainted the surfaces to prevent recurrence. Visual inspections of the external surfaces of the gas turbine fuel storage tanks in December 2006 detected no loss of material due to corrosion.

Thickness measurements of the gas turbine fuel storage tanks in April 2002 found pitting up to 60 percent through-wall with no loss of intended function. This pitting was repaired with a weld overlay. Internal inspections of the IP2 fire water and the training center fire water storage tanks in 2003 detected failure of the coating in several places but no appreciable metal loss, Corrective actions repaired the coating.

The staff confirmed detection of degradation and corrective action prior to loss of intended function assures program effectiveness in managing the aging effects for these passive components.

Furthermore, the staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.1 and A.3.1.1, the applicant provided the UFSAR supplement for the Aboveground Steel Tanks Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant has committed to implement the noted enhancements prior to entering the period of extended operation (Commitment 1).

Conclusion. On the basis of its audit and review of the applicant's Aboveground Steel Tanks Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancements to the program elements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 Bolting Integrity Program

Summary of Technical Information in the Application. LRA Section B.1.2 describes the existing Bolting Integrity Program as consistent with GALL AMP XI.M18, "Bolting Integrity," with enhancement.

The Bolting Integrity Program relies on NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," recommendations, industry recommendations, and EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," Volumes 1 and 2, for a comprehensive bolting integrity program with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance as in EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," for pressure-retaining and structural bolting. The program applies bolting and torquing practices of safety- and nonsafety-related bolting for pressure-retaining components, NSSS component supports, and structural joints. The program addresses all bolting regardless of size except reactor head closure studs, which are addressed by the Reactor Head Closure Studs Program. The program periodically inspects closure bolting for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Bolting Integrity Program to verify consistency with GALL AMP XI.M18. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Bolting Integrity Program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M18. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to program element, "preventive actions," specifically, "[r]evise applicable procedures to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and to clarify the prohibition on use of lubricants containing MoS_2 for bolting."

This enhancement is based on EPRI guidance and staff recommendations in NUREG-1339 and is therefore acceptable.

In Audit Item 109, the staff asked the applicant if they have a bolting expert for IP2 and IP3 as recommended in the EPRI guidance. By letter dated March 24, 2008, the applicant stated that the Maintenance Department provides the functions of the expert for bolting in accordance with the EPRI guidance. The staff found this to be acceptable because it is consistent with the EPRI guidance.

In Audit Items 241 and 270, the staff asked the applicant why loss of preload was not an aging effect requiring management. The applicant stated that EPRI Mechanical Tools, EPRI 1010639 (which is an industry guidance document), does not list loss of preload as an aging effect requiring management. The staff stated that other plants have listed loss of preload as an aging effect requiring management and the Bolting Integrity Program used to manage the aging. In addition, the GALL Report lists loss of preload as an aging effect requiring management and lists the Bolting Integrity Program as the appropriate program to manage this aging effect. The applicant stated that the Bolting Integrity Program includes provisions to manage loss of preload. By letter dated December 18, 2007, the applicant revised its commitment and amended the LRA to explicitly state that the Bolting Integrity Program manages the aging effect of loss of preload. The staff finds the applicant's response acceptable because it amended the LRA to manage loss of preload which is consistent with the guidance in the GALL Report.

Operating Experience. LRA Section B.1.2 stated that visual inspections of bolted connections were documented during 2001 through 2005. Although corrosion products were found on some bolting materials, the applicant did not identify any situations where loss of material had precluded the bolted connection from performing its intended function. The applicant completed corrective actions to ensure future integrity of the bolted connection. The applicant concluded that identification of degradation and performance of corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for passive components.

The staff notes that the applicant uses plant procedures that address material and lubricant selection, design standards, and good bolting maintenance practices consistent with EPRI guidance that results in few problems with bolting. By controlling the material (i.e., the maximum yield strength), the applicant has not experienced SCC of pressure boundary bolting.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.2 and A.3.1.2, the applicant provided the UFSAR supplement for the Bolting Integrity Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant has committed to implement the noted enhancement prior to entering the period of extended operation (Commitment 2). The applicant has also committed to use the Bolting Integrity Program to manage the loss of preload (Commitment 2).

Conclusion. On the basis of its audit and review of the applicant's Bolting Integrity Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancement to the program element and confirmed that their implementation prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Boraflex Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.3 describes the existing Boraflex Monitoring Program as consistent with GALL AMP XI.M22, "Boraflex Monitoring," with exceptions.

The Boraflex Monitoring Program prevents degradation of the Boraflex panels in the spent fuel racks from compromising the criticality analysis supporting the design of the spent fuel storage racks. The program relies on 1) areal density testing, 2) a predictive computer code, and 3) determination of boron loss through correlation of silica levels in spent fuel water samples to maintain the required five percent subcriticality margin. Corrective actions follow if test results find that the five percent subcriticality margin cannot be maintained because of current or projected Boraflex degradation. This program applies to IP2 only as no Boraflex is used for criticality control of IP3 spent fuel.

Staff Evaluation. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Boraflex Monitoring Program to verify consistency with GALL AMP XI.M22. Based on the staff's review, the staff determined that Boraflex Monitoring Program elements "scope of program," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M22. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exceptions to determine whether the program is adequate to manage the aging effects for which it is credited.

Exception 1. In the LRA, the applicant took the following exception to program element "preventive actions": "NUREG-1801 specifies measuring gap formation by blackness testing. The IPEC program specifies areal density measurements for boraflex degradation."

Exception 2. In the LRA, the applicant took the following exception to program element "detection of aging effects": "NUREG-1801 recommends blackness testing as a supplement to areal density measurements for determining gap formations. The IPEC program specifies areal density testing only."

For both exceptions, the applicant provided a footnote which read:

> The NRC Staff, as documented in the SER for Oyster Creek, has accepted the position that areal density measurement in lieu of blackness testing is acceptable. Areal density testing provides a direct measurement of in-rack performance of Boraflex panels through measurement of gaps, erosion, and general thinning. Blackness testing provides only an indication of neutron

absorber presence and does not quantitatively measure the Boron-10 areal density of neutron absorber in each rack. Therefore, areal density along with the monitoring of silica levels in the spent fuel pool provides adequate detection of boraflex degradation.

The exceptions to the GALL Report relate to one of the types of periodic tests performed to monitor and detect Boraflex degradation. The GALL Report specifies neutron attenuation/blackness testing be performed to determine gap formation in the Boraflex panels. In response to Audit Item 21, by letter dated December 18, 2007, the applicant stated that areal density measurement (BADGER testing) provides a direct measurement of in-rack performance of the boraflex panels through measurement of gaps, erosion and general thinning and quantitatively measures the Boron-10 areal density. Blackness testing provides an indication of neutron absorber presence only, and does not provide quantitative measurements of the Boron-10 areal density. Therefore, the blackness testing is not required.

The staff reviewed the exceptions and concluded that since the areal density test is more quantitative than the blackness test, these exceptions are acceptable.

In RAI 3.0.3.2.3-1, dated April 18, 2008, the staff noted that the UFSAR, Revision 20, dated 2006, Section 14.2.1 states in part that, "Northeast Technology Corporation report NET-173-01 and NET-171-02 are based on conservative projections of amount of boraflex absorber panel degradation assumed in each sub-region. These projections are valid through the end of the year <u>2006</u>." The staff requested that the applicant confirm that the Boraflex neutron absorber panels in the IP2 spent fuel pool have been re-evaluated for service through the end of the current licensing period, and that the applicant provides information on their plans for updating the Boraflex analysis during the period of extended operation.

In its response, dated May 16, 2008, the applicant provided the following information. BADGER testing was performed in February 2000, July 2003, and July 2006. The latest test data and RACKLIFE [a computer-generated value of boron loss] predictive code indicate that the Boraflex neutron absorbing panels will meet the TS requirements through the end of the current licensing period. The next BADGER test will be performed prior to the end of calendar year 2009. Periodic BADGER testing and RACKLIFE projections will continue through the period of extended operation to confirm acceptable Boraflex condition. The appropriate UFSAR section will be updated in the next revision to reflect this.

By letter dated October 20, 2008, the applicant transmitted the most recent UFSAR which included the following statement:

> Based upon BADGER testing in calendar years 2003 and 2006 and RACKLIFE code projections, the validity of the criticality and boron dilution analysis documented in NET-173-01 and NET-173-02 can be extended through the end of the current license (September 30, 2013), provided BADGER testing is performed during calendar year 2009 and again in 2012 to confirm the progression of localized Boraflex dissolution.

Because the applicant updated its UFSAR to reflect that the analysis will be valid through the end of the current license, the staff's concern is resolved.

Operating Experience. LRA Section B.1.3 states that panels of Boraflex maintain adequate subcriticality of the fuel in the spent fuel racks. As Boraflex is susceptible to in-service degradation, the applicant developed a RACKLIFE model of the IP2 spent fuel pool. Results of Boron-10 areal density gage for evaluating racks (BADGER) testing in February 2000, July 2003, and again in July 2006, confirmed the predictions of the RACKLIFE computer model and proved that the program effectively manages change in material properties (reduction in neutron-absorbing capacity) for Boraflex neutron absorber panels.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10.

The GALL Report, Section XI.M22 in "Operating Experience," states:

> The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the period of extended operation, the measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets will maintain their integrity and will be effective in performing its intended function.

The applicant has provided information in a response to an Audit Item, and has updated its UFSAR to reflect the performance of BADGER testing. Therefore, the staff finds that the applicant has considered the appropriate plant-specific and industry operating experience.

UFSAR Supplement. In LRA Section A.2.1.3, the applicant provided the UFSAR supplement for the Boraflex Monitoring Program. The staff reviewed this section and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Boraflex Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 Diesel Fuel Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.9 describes the existing Diesel Fuel Monitoring Program as consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions and enhancements.

The Diesel Fuel Monitoring Program entails sampling for whether adequate diesel fuel quality is maintained to prevent loss of material and fouling in fuel systems. Periodic draining and cleaning of tanks and verification of new oil quality before its introduction into the storage tanks minimize exposure to fuel oil contaminants (e.g., water, microbiological organisms). Sampling and analysis are in accordance with the IP2 and IP3 fuel oil purity technical specifications and ASTM Standards D4057-95 and D975-95 (or later revisions of these standards). Thickness measurements of storage tank bottom surfaces verify whether degradation has occurred. The One-Time Inspection Program describes inspections planned to verify the effectiveness of the Diesel Fuel Monitoring Program.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Diesel Fuel Monitoring Program to verify consistency with GALL AMP XI.M30. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Diesel Fuel Monitoring Program element "corrective actions" is consistent with the corresponding element in GALL AMP XI.M30. Because this element is consistent with the GALL Report element, the staff finds that it is acceptable.

As documented in the Audit Report, the staff verified the sampling frequencies for the EDGs, gas turbine generators, diesel fire pump, Appendix R diesel generators, and security diesel generator fuel oil storage tanks. Enhancements to the Diesel Fuel Monitoring Program, discussed below, include draining, cleaning, and inspection and bottom thickness measurement once every ten years for the gas turbine generators fuel oil storage tanks, the EDGs fuel oil storage and day tanks, and the Appendix R diesel generators fuel oil storage and day tanks. In addition, an enhancement to the Diesel Fuel Monitoring Program provides for periodic sampling, near the bottom, once per month to determine water content in the gas turbine generators fuel oil storage tanks, the EDGs fuel oil storage and day tanks, the diesel fire pumps storage tanks, the security diesel generator storage tank, and the Appendix R diesel generators fuel oil storage tanks. The staff determined that the sampling frequencies are consistent with current industry standards, and are consistent with the plant technical specifications. The sampling frequencies will provide for timely detection of fuel oil contamination, and will allow corrective actions to be taken, as needed, prior to the loss of intended function. On this basis, the staff finds these sampling frequencies acceptable.

The staff reviewed the exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Exception 1. In the LRA, the applicant took the following exception to the GALL Report program element "scope of program": "NUREG-1801 recommends use of ASTM Standards D2276 and D6217. Particulate testing is performed using the guidelines of ASTM Standard D2276."

The staff noted that the discussion of this exception in LRA Section B.1.9 includes a footnote, which states the following: "ASTM Standard D6217 (particulate by filtration) is not used for determination of particulate. Particulate testing is performed using standard D2276. The guidelines of D2276 are appropriate for determination of particulates and the plant technical specifications specify this standard."

The staff noted that GALL Report, Section XI.M30 recommends ASTM D2276 and D6217 for the measurement of particulates in diesel fuel. The staff reviewed both standards and determined that the guidelines of D2276 are appropriate for determination of particulates and the plant technical specifications specify this standard. Therefore, the staff concludes that this exception is acceptable.

Exception 2. In the LRA, the applicant took the following exception to the GALL Report program elements "scope of program," "parameters monitored or inspected," and "acceptance criteria": "NUREG-1801 recommends use of ASTM Standards D1796 and D2709. Only ASTM Standard D1796 is used for testing water and sediment."

The staff noted that the discussion of this exception in LRA Section B.1.9 includes a footnote, which states the following: "The guidelines of ASTM Standard D1796 are used rather than those of ASTM Standard D2709 (water and sediment by centrifuge for lower viscosities) for determination of water and sediment. The two standards are applicable to oils of different viscosities. Standard D1796 is applicable to the fuel oil used at IPEC."

ASTM Standard D1796 and 2709 are applicable to oils of different viscosities. Although the GALL Report specifies the use of ASTM Standard D2709, ASTM Standard D1796 is applicable to the fuel oil used at IP. Determination of water and sediment are established in site procedures. The staff also confirmed that the guidance presented in ASTM standard D1796 applies to fuel oils with the viscosity of that used at IP2 and IP3. Therefore, the staff concludes that this exception is acceptable.

Exception 3. In the LRA, the applicant took the following exception to the GALL Report program element "preventive actions": "NUREG-1801 specifies fuel oil is maintained by addition of biocides. IPEC does not add biocide to diesel fuel oil storage tanks."

The staff noted that the discussion of this exception in the Diesel Fuel Monitoring Program includes a footnote, which states the following:

> IPEC does not add biocides to diesel fuel oil storage tanks. Since water contamination in the diesel fuel oil storage tanks is minimized, the potential for MIC [microbiologically-influenced corrosion] is limited. The IPEC process for review of site and industry operating experience ensures that if MIC is discovered during future analyses, appropriate corrective actions will be taken, including modification of program attributes, if appropriate.

The IP2 and IP3 program does not add biocides to diesel fuel oil storage tanks on a routine basis to prevent biological breakdown of the diesel fuel (i.e., microbiologically-influenced corrosion). Rather, the program is focused on limiting the potential for microbiologically-influenced corrosion by minimizing the water concentration of the fuel. If the results of routine samples indicate evidence of MIC activity, the need for biocides is evaluated under the corrective action program. If the evaluation deems them necessary to correct the condition, biocides will be used. This practice is consistent with guidance contained in ASTM Special Technical Publication 1005, "Distillate Fuel: Contamination, Storage and Handling." 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.

Since water contamination in the diesel fuel storage tanks is minimized, the potential for microbiologically-influenced corrosion is limited. The staff confirmed that the applicant's process for review of site and industry operating experience ensures that if microbiologically-influenced corrosion is discovered during future analyses, appropriate corrective actions will be taken, including modification of program attributes, if appropriate. Therefore, the staff finds that this exception is acceptable.

Exception 4. In the LRA, the applicant took the following exceptions to the GALL Report program elements "parameters monitored or inspected" and "acceptance criteria," which were revised by Amendment 1 to the LRA, Attachment 1, Audit Item 131, dated December 18, 2007. Specifically, the exception stated, "[f]or determination of particulates, NUREG-1801 recommends use of modified ASTM Standard D2276 Method A and D6217. Determination of particulates is according to ASTM Standard D2276."

The staff noted that the discussion of this exception in Section B.1.9 of the LRA includes a footnote. The footnote to this exception was revised by Amendment 1 to the LRA, Attachment 1, Audit Item 131, dated December 18, 2007. The revised footnote states the following:

> Determination of particulates is according to ASTM Standard D2276 which conducts particulate analysis using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801. ASTM D6217 applies to middle distillate fuel using a smaller volume of sample passing over the 0.8 micron filter. Since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method, use of D2276 only is more conservative.

The staff noted that GALL Report Section XI.M30 recommends modified ASTM D2276, Method A, and ASTM D6217 for the measurement of particulates in diesel fuel. The modification to D2276 consists of using a filter with a pore size of 3.0 micron, instead of 0.8 micron. The staff reviewed both standards and determined that the guidelines of D2276 are appropriate for determination of particulates at IP and the use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method. Therefore, the staff concluded that this exception is acceptable.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements "preventive actions" and "detection of aging effects":

> IP2: Revise applicable procedures to include cleaning and inspection of the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank once every ten years.
>
> IP3: Revise applicable procedures to include cleaning and inspection of the EDG fuel oil day tanks, Appendix R fuel oil storage tank, and Appendix R fuel oil day tank once every ten years.

As discussed in the applicant's procedures, the EDG and GT2/3 gas turbine fuel storage tanks are cleaned and inspected every ten years to remove sludge, debris, and water. Program enhancements are needed to include the GT1 storage tank, EDG fuel oil day tanks, Appendix R fuel oil storage tank and the SBO/Appendix R diesel generator fuel oil day tanks.

The GT1 tanks are monitored in accordance with technical specifications on fuel oil purity and the guidelines of ASTM Standards D1796 (water and sediment by centrifuge), D2276 (particulate gravimetrically), and D4057 (sampling). In addition the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank are periodically sampled, near the bottom, to determine water content. The frequencies and acceptance criteria are documented in the applicant's procedures.

In Audit Item 36, the staff asked the applicant to provide a technical basis for the 10-year inspection frequency. In its response, dated March 24, 2008, the applicant stated that the basis for the 10-year wall thickness inspection frequency is to perform the inspections in conjunction with other 10-year inspections and cleanings. This inspection frequency is consistent with the recommended frequency in RG 1.137 and meets New York State regulations for fuel oil storage tanks. Past visual inspections of fuel oil storage tanks have not detected significant degradation that would lead to a need for an increased inspection frequency.

The staff determined that the applicant's enhancement will add routine draining, cleaning, and visual inspections, and ultrasonic measurement of the bottom surfaces of the diesel generators fuel oil storage tanks and day tanks and gas turbine generators fuel oil storage tanks, which are consistent with the recommendations in the GALL Report. The frequency for draining, cleaning and inspecting the tanks will be based on past experience, which has been demonstrated to provide acceptable performance for the diesel fuel storage tanks. The enhancement to the diesel fuel oil monitoring program ensures that significant degradation is not occurring. On this basis, the staff found this enhancement acceptable.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements “preventive actions,” “detection of aging effects,” and “monitoring and trending”:

> IP2: Revise applicable procedures to include quarterly sampling and analysis of the SBO/Appendix R diesel generator fuel oil day tank and security diesel fuel oil day tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be < 10mg/l. Water and sediment acceptance criterion will be < 0.05%.
>
> IP3: Revise applicable procedures to include quarterly sampling and analysis of the Appendix R fuel oil storage tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be < 10 mg/l. Water and sediment acceptance criterion will be < 0.05 %.

As described in the applicant's procedures, IP2 and IP3 perform periodic multi-level sampling to provide assurance that fuel oil contaminants are within acceptable limits. Water and particulate concentrations are monitored and trended at least quarterly or in accordance with technical specifications. This enhancement expands scope of existing procedures to include quarterly sampling and analysis of all tanks within the scope of license renewal.

During the regional inspection conducted in February 2008, the inspectors identified that the IP2 security diesel fuel oil storage tank was not included in the program enhancement to perform fuel oil chemistry sampling. By letter dated March 24, 2008, the applicant amended the above enhancement to include quarterly sampling of the IP2 security diesel fuel oil storage tank.

The staff determined that the applicant's enhancement will add routine diesel fuel oil sampling and analysis for the SBO/Appendix R diesel generator fuel oil day tank (IP2), the Appendix R fuel oil storage tank (IP3), and the security diesel fuel oil storage and day tanks (IP2), which is consistent with the recommendations in the GALL Report. The frequency for sampling and analysis is consistent with the technical specifications where applicable. The enhancement to the diesel fuel oil monitoring program ensures that fuel oil quality is maintained. On this basis, the staff finds this enhancement acceptable.

<u>Enhancement 3</u>. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects":

> IP2: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel day tank, GT1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank once every ten years.
>
> IP3: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil day tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank once every ten years.

The enhancement is necessary to provide periodic thickness measurement monitoring for all tanks within scope of license renewal. Presently, the only diesel fuel oil tanks with procedures or tasks requiring NDE of the tank bottom are the IP3 EDG storage tanks and the GT2/3 storage tank. These inspections are described in the applicant's procedures. The minimum acceptable thickness for each tank bottom when inspected is based upon a component-specific engineering evaluation. Wall thickness will be acceptable if greater than the minimum wall thickness for the specific component.

As described in the applicant's procedure, thickness measurements are performed once every ten years on the IP3 EDG fuel oil storage tanks to verify that significant degradation is not occurring. The Aboveground Steel Tanks Program includes thickness measurement of the GT2/3 fuel oil storage tank once every ten years. Enhancement is also needed to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program (see Enhancement 5, below).

The staff determined that the applicant's enhancement will add routine draining, cleaning, visual inspections, and ultrasonic measurement of the bottom surfaces of the diesel fuel tanks, which are consistent with the recommendations in the GALL Report. The frequency for draining, cleaning and inspecting the tanks will be based on past experience, which has been demonstrated to provide acceptable performance for the diesel fuel storage tanks. Ultrasonic measurement of the tank bottoms will provide objective evidence that degradation of the tanks is not occurring. The staff finds that the selection of the tank bottoms for ultrasonic inspection is appropriate since any moisture in the oil will tend to settle to the bottom of the tanks, making this the most susceptible location for degradation. On this basis, the staff found this enhancement acceptable.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program element "monitoring and trending":

> IP2: Revise appropriate procedures to change the GT1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency.
>
> IP3: Revise appropriate procedures to change the Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency.

The enhancement is necessary to address all tanks within scope of license renewal. The diesel fuel oil sampling and analysis frequencies for water and particulates are included in the applicant's procedures and the technical specifications, as applicable.

The staff determined that the applicant's enhancement will add routine quarterly frequency diesel fuel oil sampling and analysis from the GT1 gas turbine generator and diesel fuel oil storage tanks at IP2 and the Appendix R diesel generator fuel oil day tank and the diesel fire pump storage tank at IP3, which are consistent with the recommendations in the GALL Report. The frequency for sampling and analysis is consistent with the technical specifications where applicable. The enhancement to the diesel fuel oil monitoring program ensures that fuel oil quality is maintained. On this basis, the staff found this enhancement acceptable.

Enhancement 5. In the LRA, the applicant committed to implement the following enhancement to program element "acceptance criteria": "[r]evise applicable procedures to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program."

The enhancement is necessary to specify acceptance criteria for thickness measurements for all tanks within scope of license renewal. See Enhancement 3, above.

Presently, the only diesel fuel oil tanks with procedures or tasks requiring NDE of the tank bottom are the IP3 EDG storage tanks and the GT2/3 storage tank. These inspections are described in plant procedures. The minimum acceptable thickness for each tank bottom when inspected is based upon a component-specific engineering evaluation. Wall thickness will be acceptable if greater than the minimum wall thickness for the specific component.

The staff determined that the applicant's enhancement will specify acceptance criteria for thickness measurements of diesel generator fuel storage tanks within the scope of this program, which is consistent with the recommendations in the GALL Report. The acceptance criteria will provide a measure to determine whether corrective actions are required based upon inspection results. On this basis, the staff finds this enhancement acceptable.

Enhancement 6. In Amendment 1 to the LRA, dated December 18, 2007, in response to Audit Item 128, the applicant committed to implement the following enhancement to program element "preventive actions": "[r]evise applicable procedures to direct samples to be taken near the tank bottom and include direction to remove water when detected."

The enhancement is necessary to ensure that applicable fuel oil sampling procedures include specific direction to obtain samples near the bottom of all tanks within scope of this program in order to more accurately determine the water content. If large amounts of water are encountered the applicable fuel oil sampling procedures will provide direction to remove water from the bottom of the tank. This commitment was included in Amendment 1 to the LRA, dated December 18, 2007.

By letter dated December 18, 2007, in response to the staff's inquiries about how water content of fuel oil tanks was to be determined and how removal of water from the bottoms of fuel oil tanks was to be implemented, the applicant stated that procedure 0-CY-1810, which covers the monitoring of all diesel fuel oil on the site, will be enhanced to include direction to take samples near the tank bottom for water detection and to remove water from the tank bottom if detected (Audit Item 128).

The staff determined that the applicant's program and procedure enhancement will adequately detect the water near the bottom of fuel oil tanks within scope of this program and provide direction to remove water from the tanks when it is detected, which is consistent with the recommendations in the GALL Report. The preventive actions will provide administrative controls to detect water near the bottom of fuel oil tanks and provide direction to remove water from the tanks when it is detected. On this basis, the staff finds this enhancement acceptable.

Enhancement 7. In Amendment 1 to the LRA, dated December 18, 2007, in response to Audit Item 132, the applicant committed to implement the following enhancement to program element "preventive actions": "[r]evise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed."

The enhancement is necessary to ensure that applicable administrative controls are in place to direct the addition of biocides to control biological activity when it is detected in fuel oil tanks within scope of this program as recommended in the GALL Report to prevent biological breakdown of the diesel fuel. This commitment was included in Amendment 1 to the LRA, dated December 18, 2007.

By letter dated December 18, 2007, in response to the staff's inquiries about the addition of biocides to control biological activity in diesel fuel oil, the applicant stated that the corrective actions program is used to evaluate microbiological activity and determine the need for the use of biocides (Audit Item 132). The applicant follows the guidelines of ASTM Special Technical Publication 1005, "Distillate Fuel: Contamination, Storage, and Handling," with regard to the addition of biocides to diesel fuel oil. In order to make the procedures regarding the addition of biocides to diesel fuel oil consistent between IP2 and IP3, the applicant stated that an enhancement will be added to combine the directions from unit procedures into series procedure for the addition of chemicals, including biocide, on both units when the presence of biological activity is confirmed.

The staff determined that the applicant's program and procedure enhancement will adequately provide direction for the addition of chemicals, including biocide, to the diesel fuel oil storage tanks within the scope of this program on both units when the presence of biological activity is confirmed. The preventive actions will provide administrative controls to direct the addition chemicals, including biocide, to the diesel fuel oil storage tanks when the presence of biological activity is confirmed. On this basis, the staff finds this enhancement acceptable.

Enhancement 8. During the regional inspection, the inspectors identified that the existing procedure for fuel oil transfer using the emergency fuel oil transfer trailer did not specify a that chemistry oil sample be taken at the tank bottom, and did not provide specific acceptance criteria as to when tank flushing would be required. In Amendment 3 to the LRA, dated March 24, 2008, the applicant committed to implement the following enhancement to program element "preventive actions": "[r]evise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks."

The staff determined that the applicant's program and procedure enhancement will provide direction for sampling the portable fuel oil tanker contents prior to transfer to the storage tanks. The preventive actions will provide administrative controls to ensure that possible contaminants will not be transferred into the emergency diesel fuel oil supply system. On this basis, the staff finds this enhancement acceptable.

Operating Experience. LRA Section B.1.9 states that results of a vendor microorganism study of a sample taken from an EDG underground diesel fuel tank reported heavy bacteria growth. The source of the bacteria was water intrusion through an overfill line spool piece incorrectly reassembled following maintenance. After removal of the water from the tank, testing found no bacteria. Detection of out-of-specification fuel conditions demonstrates the program's ability to detect potentially detrimental diesel fuel conditions. Subsequent corrective actions enhance the program's ability to remain effective in managing loss of component material.

A QA surveillance in 2004 found the overall program effective. One deficiency found and corrected was a missed surveillance. Detection of program deficiencies and subsequent corrective actions add assurance that the program will continue to manage loss of component material effectively.

Other than the noted instances, fuel oil sampling results from 2001 through 2005 reveal that fuel oil quality is maintained in compliance with acceptance criteria. Continuing acceptable diesel fuel quality assures program effectiveness in managing loss of fuel system component material.

Visual inspection of an IP3 EDG fuel oil storage tank in 2001, visual and ultrasonic testing inspections of the two other EDG fuel oil storage tanks in 2001, and visual inspection of the IP2 fuel oil storage tanks in 2003 found no significant degradation.

The staff's review of the operating experience presented by the applicant indicates diesel fuel oil qualify has been maintained and that out-of-specification or deteriorating condition have been detected and corrected. The staff determined that the applicant's program, with the implementation of the proposed procedure enhancements, will adequately maintain diesel fuel oil quality for the tanks within the scope of the program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.8 and A.3.1.8, the applicant provided the UFSAR supplement for the Diesel Fuel Monitoring Program. In response to Audit Items 128 and 132, in Amendment 1 to the LRA, dated December 18, 2007, the applicant revised LRA Sections A.2.1.8 and A.3.1.8 to include the following (Commitment 4):

> Revise applicable procedures to direct samples taken near the tank bottom and include direction to remove water when detected.
>
> Revise applicable procedures to direct the addition of chemicals including biocides when the presence of biological activity is confirmed.

In Amendment 3 to the LRA, Attachment 1, dated March 24, 2008, the applicant added the following enhancement and committed to implementing it prior to the period of extended operation (Commitment 4):

> Revise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks.

The staff reviewed these sections and determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Diesel Fuel Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements to the program elements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 External Surfaces Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.11 describes the existing External Surfaces Monitoring Program as consistent with GALL AMP XI.M36, "External Surfaces Monitoring," with enhancement.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the External Surfaces Monitoring Program to verify consistency with GALL

AMP XI.M36. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the External Surfaces Monitoring Program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M36. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to the program element "scope of program":

> External Surfaces Monitoring Program guidance documents will be revised to require periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).

The staff reviewed the proposed enhancement and finds it acceptable because implementation of the enhancement will result in the periodic inspection of those systems identified by the applicant as within the scope of license renewal in accordance with 10 CFR 54.4(a), which is consistent with the GALL Report.

Operating Experience. In LRA Section B.1.11, the applicant summarizes the operating experience review it performed for the External Surfaces Monitoring program. The applicant reviewed operating experience for the five-year period covering 2001 through 2005, for both IP2 and IP3. The review was documented in a report that was reviewed by the staff during an onsite review. As stated in LRA Section B.0.4, for monitoring programs, such as the External Surfaces Monitoring program, the applicant reviewed sample results to determine if parameters are being maintained as required by the program. During an audit, the staff reviewed the sample results produced by the applicant, and in addition, independently reviewed additional reports that contained keywords such as rust/rusted/rusting, residue, corroded, encrustation, paint, flakes/flaking, etc. Such keywords would likely be included in condition reports to describe a degraded exterior surface of a component. Based on the review of the applicant-identified operating experience, and the independent review of additional condition reports, the staff has confirmed that the applicant has addressed operating experience related to this program, and has identified the applicable aging effects, i.e., loss of material, which is the aging effect identified by the GALL Report for this AMP. Therefore, the staff determines that the applicant has adequately addressed this program element.

UFSAR Supplement. In LRA Sections A.2.1.10 and A.3.1.10, the applicant provided the UFSAR supplement for the External Surfaces Monitoring Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.10 and A.3.1.10, the applicant has committed to enhance this program prior to entering the period of extended operation (Commitment 5).

Conclusion. On the basis of its review of the applicant's External Surfaces Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement to the program element and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. Lastly, the staff confirmed that the applicant addressed operating experience related to this program, and identified the applicable aging effects. Therefore, the staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 Fatigue Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.12 describes the existing Fatigue Monitoring Program as consistent with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary," with exception and enhancement.

The Fatigue Monitoring Program tracks the number of critical thermal and pressure transients for selected reactor coolant system components to validate the analyses of fatigue transients by assuring that the actual effective number does not exceed the analyzed number of transients.

In a letter dated January 22, 2008, the applicant amended LRA Section B.1.12, Fatigue Monitoring, to provide detailed information on the cycles counting and the methodology that will be used for the determination of stresses and fatigue usage, including the environmental effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Fatigue Monitoring Program to verify consistency with GALL AMP X.M1. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Fatigue Monitoring Program elements "scope of program," "preventive actions," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP X.M1. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exception and enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

During the audit, the staff asked the applicant to provide more information regarding the actions or alarm limits that will trigger the corrective action for the applicant to update fatigue usage calculations (Audit Item 40). In a letter dated March 24, 2008, the applicant stated that, in accordance with their procedure, alert levels will be calculated by adding twice the number of cycles from the last fuel cycle to the total number of cycles to date. The applicant stated that they will take corrective actions if this alert level is greater than the analyzed transients.

In a letter dated April 18, 2008, in RAI 4.3.1.8-2, the staff also asked the applicant to explain the corrective actions and the frequency of such actions if the alert level is approached. In the applicant's response, dated May 16, 2008, the applicant explained that the frequency of updates for the counting of plant transients is at least once each operating cycle, and these updates determine if design transients may be exceeded before the next update. The applicant also stated that corrective actions will be taken prior to exceeding the analyzed transient cycles.

The staff finds the applicant's response acceptable because the applicant will perform periodic updates on the counting of plant transients, which ensures that design transients will not be exceeded and will allow adequate time for corrective actions to be initiated based on the alert level from the applicant's procedure on cycle counting and tracking. These corrective actions include further re-analysis or repair or replacement of the affected components. The staff also finds the applicant's response acceptable because the applicant will appropriately include the new or updated CUF calculations for all NUREG/CR-6260 locations identified in LRA Tables 4.3-12 and 4.3-13 to be a part of the Fatigue Monitoring Program and the incurred cycles will be monitored and the applicant will ensure that they do not exceed the analyzed number of cycles. Based on the staff's conclusions this issue is resolved.

Exception. The staff noted that the applicant originally took exception to the "detection of aging effects" program element of the GALL AMP X.M1 recommendation. The applicant stated that "updates of fatigue usage calculations are not necessary unless the number of accumulated fatigue cycles approaches the number of analyzed design cycles." In a letter dated January 22, 2008, the applicant amended the LRA with respect to its basis for its environmentally-assisted fatigue analysis. In this letter, the applicant provided clarification regarding the relationship between Commitment 33 and the FMP. The applicant stated that as part of Commitment 33, refined CUF calculations will be provided to the NRC. The applicant amended the LRA so that Commitment 33 is within the scope of the applicant's Fatigue Monitoring Program and to credit this AMP as the basis for accepting this TLAA and other TLAAs described in LRA Section 4.3.1.1 through 4.3.1.8 in accordance with 10 CFR 54.21(c)(1)(iii).

During a teleconference with the applicant on April 3, 2008, the staff asked the applicant if the exception to the "detection of aging effects" program element in GALL AMP X.M1 will still be taken based on the applicant's changes made in LRA Amendment 2, dated January 22, 2008. The applicant's proposed change to have refined CUF calculations is consistent with the NRC's recommendations for the periodic CUF updates in the "detection of aging effects" program element of GALL AMP X.M1. Also the applicant stated in Commitment No. 33 that the actions to replace or repair components before exceeding a CUF of 1.0 are consistent with the corrective actions recommended in the program element, "corrective action" program element of GALL AMP X.M1.

The staff verified that, in a letter dated June 11, 2008, the applicant amended the LRA and removed the exception to the "detection of aging effects" program element in GALL AMP X.M1. Based on this assessment and the applicant's removal of the exception taken to GALL AMP X.M1 and clarification on the corrective actions for the program, the staff concludes that the "detection of aging effects" and "corrective actions" program elements for the Fatigue Monitoring Program are consistent with and conform to the staff's "detection of aging effects" and "corrective actions" program element criteria that are recommended in GALL AMP X.M1 without exception, and that these program elements are, therefore, acceptable. The staff's question on the exception taken to GALL AMP X.M1 is resolved.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to the program element "parameters monitored or inspected":

> IP2: Perform an evaluation to confirm that monitoring steady state cycles is not required or revise appropriate procedures to monitor steady state cycles. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures.
>
> IP3 Enhancements: Revise appropriate procedures to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.

During the audit, the staff noted that in the LRA the IP2 enhancement included monitoring steady state cycles, but the program basis document discussed both steady state cycles and feedwater cycles. The staff asked the applicant to clarify the discrepancy (Audit Item 164).

In a letter dated March 24, 2008, the applicant submitted an amendment to the LRA, and stated that feedwater cycles are included in the enhancement. The staff reviewed these changes and noted that the revised statement is in agreement with the Commitment 6. Therefore, the staff finds the applicant's response acceptable.

The staff finds that after implementation of these enhancements, the "parameters monitored or inspected" program element will be consistent with the staff's "parameters monitored or inspected" program element criteria that are recommended in GALL AMP X.M1. On this basis, the staff finds these enhancements acceptable.

The staff reviewed those portions of the Metal Fatigue of Reactor Coolant Pressure Boundary Program for which the applicant claims consistency with GALL AMP X.M1 and finds that they are consistent with the GALL Report AMP. The staff finds the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program acceptable because it conforms to the recommended AMP, as subject to the enhancements that have been discussed and evaluated in the previous paragraphs and that have been incorporated into Commitment 6.

Operating Experience. LRA Section B.1.12 states that the program re-evaluates usage factors as appropriate (e.g., certain auxiliary transients related to charging and letdown approaching typical design cycle limits for the IP2 charging nozzles during the current period of operation). The assessment of impact of thermal transient cycles on the IP2 nozzles compared plant-specific against previously-assumed moment loads and reconciled the cycle counts to design cycles in previous analysis. The reevaluation concluded that the fatigue impact of transient cycles accumulated on the IP2 charging nozzles is within expectations based on pro-rated typical operation of the charging system and projected allowable cycles during the current period of operation.

The staff noted, from the applicant's license renewal plant operating experience review report for this AMP, that the applicant has factored in industry experience, which includes the thermal and operating stresses that were not considered during the original plant design related to NRC Bulletins 88-08 and 88-11, and will continue to factor in industry experience in the IP Fatigue Monitoring Program. During the audit, the staff reviewed implementing procedures and problem identification reports related to the applicant's Metal Fatigue Program. The staff noted that the applicant demonstrated that the program monitors transients and tracks their accumulation based on the applicant's implementing procedure. The staff noted that the applicant tracked and monitored reactor shutdowns and startups and their cycle limitations did not indicate that the allowable number of cycles would be exceeded. The staff also interviewed the applicant's technical staff who have specialized knowledge of the program. The staff reviewed instances previously documented by the applicant that identified issues with the Metal Fatigue Program and where the applicant had implemented corrective actions. The staff's review demonstrated that the operating experience shows that this program effectively manages aging effects; therefore, continued implementation of the program assures management of the effects of aging so components crediting this program will perform intended functions consistent with the CLB during the period of extended operation

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.11 and A.3.1.11, the applicant provided the UFSAR supplement for the Fatigue Monitoring Program. By letter dated March 24, 2008, the applicant revised LRA Section A.2.1.11 to include feedwater cycles (in response to Audit Item 164). The staff reviewed these LRA sections, as revised, and the amendments made to Commitments 6 and 33. The staff verified that LRA Sections A.2.1.11 and A.3.1.11 include Commitment 6. The staff also verified that the applicant amended the Fatigue Monitoring Program to incorporate the corrective actions for the applicant's TLAA on metal fatigue, as defined in Commitment 33. Based on this review, the staff finds that the UFSAR Supplement Sections A.2.11 and A.3.1.11, as amended by letter dated January 22, 2008, and as revised by letter dated March 24, 2008, provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fatigue Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancement to the program element and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 supplement for this program and concludes 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. LRA Section B.1.13 describes the existing Fire Protection Program as consistent with GALL AMP XI.M26, "Fire Protection," with exception and enhancements.

The Fire Protection Program includes fire barrier, reactor coolant pump oil collection system, and diesel-driven fire pump inspections. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors and periodic visual inspection and functional tests of fire rated-doors to maintain their operability. The diesel-driven fire pump inspection requires periodic testing and inspection of the pump and its driver so diesel engine subsystems, including the fuel supply line, can perform intended functions. The program periodically inspects and tests the Halon fire protection system (IP2) and the carbon dioxide fire protection system (IP3).

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Fire Protection Program to verify consistency with GALL AMP XI.M26. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Fire Protection Program elements "preventive actions," and "monitoring and trending," are consistent with the corresponding elements in GALL AMP XI.M26. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

The GALL Report recommends that visual inspection of approximately 10 percent of each type of fire barrier penetration seal be performed during walkdowns carried out at least once every refueling outage. These inspections examine any sign of degradation such as cracking, seal separation from wall and components, separation of layers of material, rupture and puncture of seals, which are directly caused by increased hardness, and shrinkage of seal material due to weathering.

In RAI 3.0.3.2.7-1, dated February 13, 2008, the staff noted that LRA Table 2.4-4 lists fire stops and fire wrap as bulk commodities that perform an intended function as fire barriers. LRA Table 3.5.2-4, 'Bulk Commodities," identifies the material, environment and aging effect requiring aging management for these two commodities. The Fire Protection Program is identified in the AMR, along with Note J, which indicates that neither the component nor the material and environment combination is evaluated in the GALL Report. However, in LRA Section B.1.13, "Fire Protection," there is no indication that fire stops and fire wraps are included as commodities whose aging effects will be managed by the AMP. The staff requested that the applicant describe how the aging effects of cracking/delamination, separation (for fire stops), and loss of material (for fire wrap) will be managed under the Fire Protection AMP.

In its response, dated March 12, 2008, the applicant stated that in LRA Section B.1.13, the fire protection program is an existing program that includes fire barrier inspections. The commodities fire stops and fire wraps are considered to be fire barriers which are included in the scope of the Fire Protection Program. Each fire stop (penetration seal) is visually inspected for cracking, delaminating, separation, and change in material properties at least once every seven operating cycles (15 percent every 24 months). Fire wraps are visually inspected at least once every 24 months for loss of material and any other indications of degradation or damage.

The GALL Report program states that approximately 10% of each type of penetration seal should be visually inspected at least once every refueling outage. The applicant indicated that the inspection program also requires that fire wraps be visually inspected at least once every 24 months for loss of material and any other indications of degradation or damage. The staff evaluated the applicant's program and determined that overall it meets or exceeds the penetration seal inspection frequency recommended in the GALL Report. The staff finds the fire stop and fire wrap inspection program acceptable, because it monitors material cracking, delaminating, separation, and change in fire stop and fire wrap properties.

Based on the applicant's response to RAI 3.0.3.2.7-1, dated March 12, 2008, the staff issued a follow up RAI 3.0.3.2.7-2 concerning inspection of inaccessible fire barrier penetration seals.

During an audit, the staff reviewed bases documents (for IP3) associated with the fire protection AMP. One of the bases documents states that 15 percent of the fire seals located in fire barriers are demonstrated to be operable by visual inspection on a frequency of 24 months. However, for those penetration seals that are inaccessible, the frequency of inspection is given as "not required." By letter dated April 29, 2008, the staff requested that the applicant justify the lack of visual inspections of inaccessible penetration seals.

In its response, dated May 28, 2008, the applicant stated that as provided in response to RAI 3.0.3.2.7-1, penetration seals are inspected at least once every seven operating cycles. However, IP3 site surveillance procedure provides provisions for cases where a penetration seal may become inaccessible for periodic inspection as result of plant configuration changes (i.e., installation of new plant equipment, walls, barriers, or other obstacles). In such cases, the IP3 site procedure includes guidance for the cessation of periodic surveillance of such penetration seals, subject to preparation of a formal fire protection engineering evaluation justifying the discontinuance of periodic visual surveillance.

As stated in the IP3 bases document, the visual inspection of inaccessible penetration seals is "not required" if justified by a supporting fire protection engineering evaluation, developed in accordance with the guidance of GL 86-10. On a case-by-case basis, the inaccessibility of any such penetration seal must be justified, and the fire protection adequacy of the configuration must be demonstrated. The evaluation, as stated in the bases document, must include assessment of proximate combustible loading, mitigating features, and the consequences of potential failure of the affected seal.

The applicant further stated that if the formal fire protection engineering evaluation (prepared in accordance with guidance of GL 86-10) demonstrates that the penetration seal is inaccessible for inspection, that the fire challenge to the barrier is insubstantial, and the consequences of failure of the seal would not compromise fire safety or nuclear safety, then periodic surveillance of that specific seal is not required.

The applicant clarified in the above response that the IP3 fire barrier penetration seal surveillance procedure includes inspection provisions for inaccessible fire barrier penetration seals based on a change in plant fire area configuration. The applicant stated that, for a plant change, an engineering evaluation based on guidance provided in GL 86-10[5] must be

[5] GL 86-10 is the means by which a licensee may make changes to the approved fire protection program without prior approval of the Commission in accordance with the standard license condition provided that the changes do not adversely affect the plant's ability to achieve and maintain post-fire safe-shutdown.

conducted to evaluate fire area configuration and to declare if a fire barrier penetration seal is inaccessible for periodic inspection.

The staff reviewed the applicant's response and found that it did not address the fact that GL 86-10 evaluations exist for all inaccessible fire barrier penetration seals; the response only indicated that it is a part of the fire protection program to perform such analysis. The staff requested the applicant to confirm that these analyses do exist and are periodically reviewed/updated to ensure their continued applicability. This was identified as Open Item 3.0.3.2.7-1.

By the letter dated January 27, 2009, the applicant stated that there are no IP3 fire barrier penetration seals excluded from periodic inspection due to inaccessibility. Therefore, there are no corresponding engineering evaluations.

The applicant clarified the IP3 fire barrier penetration seal program does not exclude periodic inspection of any inaccessible seal. The staff concludes that the concerns identified in Open Item 3.0.3.2.7-1 have been resolved. Therefore, Open Item 3.0.3.2.7-1 is closed.

Exception. In the LRA, the applicant took the following exception to the GALL Report program element "detection of aging effects":

> The NUREG-1801 program recommends that testing and inspection of the Halon (IP2) and CO_2 (IP3) fire suppression systems occur at least once every six months. However, IPEC performs inspection every six months, functional testing is performed every 18 months for Halon 1301 and 24 months for CO_2.

During the audit and review, the staff asked the applicant to provide technical justification why the proposed testing frequency is acceptable to detect degradation of the Halon 1301 and CO_2 fire suppression systems before the loss of the components' intended function (Audit Item 150).

In its response, dated March 24, 2008, the applicant stated that a review of past performance functional testing of Halon 1301 and CO_2 fire suppression systems has indicated no adverse material degradation that requires adjustment of the testing frequencies reported in the condition reporting database. This condition reporting database was similarly reviewed and revealed no indication of adverse material degradation.

The 18-month functional test frequency for the Halon 1301 and 24 months for CO_2 fire suppression systems is part of the current licensing basis documented in NRC IP2 SER dated October 31, 1980, and NRC IP3 SER dated April 20, 1994. The review of IP2 and IP3 operating experience indicated that these frequencies are reasonable to manage the aging effects. The functional testing frequencies are considered sufficient to ensure system availability and operability based on the plant operating history, and that there has been no aging-related event that has adversely affected system operation. Because these aging effects occur over a considerable period of time, the staff concluded that the 18-month and 24-month intervals will be sufficient to detect aging of the Halon 1301 and CO_2 fire suppression systems.

The Halon 1301 and CO_2 fire suppression systems and associated components (bolting, coil, nozzles, piping and supports, tubing, fittings, valves, and tanks) are in an inside air (external) environment. The staff found that the applicant has demonstrated that the effects of aging on the Halon 1301 and CO_2 fire suppression systems will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In addition, the staff noted that the applicant currently performs fire damper operational tests once per 12 months to detect degradation of the fire dampers before loss of the intended function. IP2 and IP3 maintenance procedures also include visual inspections of component external surfaces for signs of corrosion and mechanical damage every 6 months. The applicant's review of station operating experience identified no aging-related degradation adversely affecting the operation of the Halon 1301 and CO_2 fire suppression systems.

Although the Halon 1301 and CO_2 fire suppression system frequencies of functional testing exceed that recommended in GALL AMP XI.M26, the staff determined that it is sufficient to ensure system availability and operability with the existing surveillance which includes visual inspections of component external surfaces for signs of corrosion and mechanical damage, and verification of Halon 1301 and CO_2 storage tank weight, level, and pressure. In addition, the staff's review of the station operating history indicates no aging-related events adversely affecting system operation exist at IP2 and IP3. Based on its review of the applicant's program and plant-specific operating experience, the staff finds that the 18- and 24-month testing/surveillance frequencies for the Halon and CO_2 fire suppression systems are adequate for aging management considerations. On this basis, the staff finds this exception acceptable. The staff is adequately assured that the aging effects on the Halon 1301 and CO_2 fire suppression systems will be considered appropriately during plant aging management activities and that they will continue to perform their applicable intended functions consistent with the current licensing basis for the period of extended operation.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements, "scope of program, "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria": "IP3: Revise appropriate procedures to inspect external surfaces of the RCP oil collection system for loss of material each refueling outage."

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire Protection Program elements "scope of program, "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria," will be consistent with the GALL AMP XI.M26 program. This enhancement will enable the monitoring of the RCP oil collection system and components through inspection, providing a detailed look at system material condition to ensure external surfaces are not experiencing loss of material. This will provide additional assurance that the effects of aging are adequately managed.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements, "parameters monitored or inspected, "detection of aging effects, and "acceptance criteria":

> Revise appropriate procedures to explicitly state that the diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation that could involve items such as fuel oil, lube oil, coolant, or exhaust while running.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire protection program elements "parameters monitored or inspected, "detection of aging effects, and "acceptance criteria" will be consistent with the GALL AMP XI.M26 program. GALL AMP XI.M26, Element 3, states that the diesel fire pump is observed during performance tests for detection of any fuel supply line degradation. This enhancement is also acceptable for making the program consistent with GALL AMP XI.M26, element 6, which states that no corrosion is acceptable in the diesel-driven fire pump fuel supply line. The staff reviewed the applicant's program procedures and confirmed that these elements are consistent with the GALL Report.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program elements, "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria": "[r]evise appropriate procedures to specify that diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion or cracking at least once each operating cycle."

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire protection program element "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria," will be consistent with the GALL AMP XI.M26. GALL AMP XI.M26, Element 3, states that "periodic tests are performed at least once every refueling outage, such as ... sequential starting capability tests. This enhancement is also acceptable for making the program consistent with GALL AMP XI.M26, Element 6, which states that no corrosion is acceptable. The staff reviewed the applicant's program procedures and confirmed that these elements are consistent with the GALL Report.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program elements, "detection of aging effects," and "acceptance criteria": "IP3: Revise appropriate procedures to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage, at least once every 6 months."

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire protection program element "Detection of Aging Effects," "Acceptance Criteria" will be consistent with the GALL AMP XI.M26 program. GALL AMP XI.M26, Element 4, states that the visual inspections of the Halon/CO_2 fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. This enhancement is also acceptable for making the program consistent with GALL AMP XI.M26, Element 6, which states that no corrosion is acceptable in the Halon/CO_2 fire suppression system. The staff reviewed the applicant's program procedures and confirmed that these elements are consistent with the GALL Report.

Operating Experience. LRA Section B.1.13 states that inspections of fire stops, fire barrier penetration seals, fire barrier walls, ceilings, and floors from 2001 through 2005 revealed signs of degradation: cracks, gaps, voids, holes, or missing material. Periodic surveillances in 2001 and 2004 detected discrepancies in fire barrier wrappings. Immediate actions repaired these fire barriers. Detection of deficiencies and timely corrective actions provide confidence that the program will continue to be managed to effectively identify and minimize any loss of component material.

LRA Section B.1.13 states that a program self-assessment in 2003 found deficiencies in the fire barrier inspection list at IP2. Corrective actions reviewed the Type I fire barrier drawing against the inspection list in the procedure and changed the procedure and drawing. Detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing loss of component material.

LRA Section B.1.13 states that quality assurance audits in 2003, 2005, and 2006 revealed that the material condition of system equipment was good. The audits revealed no issues or findings that could impact program effectiveness in managing aging effects for fire protection components.

LRA Section B.1.13 states that a November 2005 inspection of the reactor coolant pump oil collection system within the IP2 containment building found no indications of loss of system component material.

Additionally, in November 2006, observations of the IP2 and IP3 diesel-driven fire pumps while they were running noted no leaks or degradation of diesel engine sub-systems, including the fuel supply line. The applicant stated that continuing monitoring provides confidence that the program effectively manages aging of diesel-driven fire pump subsystem components.

LRA Section B.1.13 states that in August 2004, the NRC completed a triennial fire protection team inspection at IP2 to assess whether the plant had implemented an adequate fire protection program and whether post-fire safe shutdown capabilities had been established and maintained properly. The inspection team also evaluated the material condition of fire area boundaries, fire doors, and fire dampers and reviewed the surveillance and functional test procedures for the diesel fire pump and other components. Additionally, the team reviewed the surveillance procedures for structural fire barriers, penetration seals, and structural steel and made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

LRA Section B.1.13 states that on May 17, 2007, the NRC completed a triennial fire protection team inspection at IP2 to assess whether the plant had implemented an adequate fire protection program and whether post-fire safe-shutdown capabilities had been established and maintained properly. The team walked down accessible portions of selected fire areas to observe material condition and the adequacy of design of fire area boundaries (including walls, fire doors and fire dampers) to ensure they were appropriate for the fire hazards in the area. The inspection team reviewed electric and diesel fire pump flow and pressure test results to ensure that the pumps were meeting their design requirements. The team reviewed the fire main loop flow test results to ensure that the flow distribution circuits were able to meet the design requirements. The team also performed a walkdown of accessible portions of the detection and suppressions systems in the selected areas as well as a walkdown of major system support equipment in other areas (e.g., fire protection pumps, Halon storage tanks and supply system) to assess the material condition of the systems and components. No findings of significance were identified.

LRA Section B.1.13 states that in January 2005, the NRC completed a triennial fire protection team inspection at IP3 to assess whether the plant had implemented an adequate fire protection program and whether post-fire safe-shutdown capabilities had been established and maintained properly. The inspection team evaluated the material condition of fire area boundaries, fire doors, and fire dampers, and reviewed the surveillance and functional test procedures for the diesel fire pump and other components. The staff also reviewed for adequacy of selected total flooding CO_2 systems and surveillance procedures for periodic system testing and the adequacy of structural fire barriers and penetration seals. The team made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing aging effects.

The staff reviewed the above operating experience and also condition reports made available during the audit, and interviewed the applicant's technical staff. The staff confirmed that the plant-specific operating experience did not reveal any degradation not already bounded by industry experience. The staff also reviewed the IP2 and IP3 operating experience reports, condition reports, and maintenance work orders associated with the corrective actions taken for the identification of signs of degradation of fire protection components. The staff confirmed that the condition reports were closed out by repairs to the degraded fire barriers or by performing adequate engineering evaluations for their acceptability. The staff noted that the applicant performs periodic inspections and places identified deficiencies into their corrective action program to ensure appropriate corrective actions are performed in a timely manner.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.12 and A.3.1.12, the applicant provided the UFSAR supplement for the Fire Protection Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.12 and A.3.1.12, the applicant has committed to enhance this program prior to entering the period of extended operation (Commitment 7).

Conclusion. On the basis of its audit and review of the applicant's Fire Protection Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exception and its justifications and determined that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes 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 System Program

Summary of Technical Information in the Application. LRA Section B.1.14 describes the existing Fire Water System Program as consistent with GALL AMP XI.M27, "Fire Water System," with exception and enhancements.

The Fire Water System Program manages water-based fire protection systems consisting of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, piping, and components tested in accordance with National Fire Protection Association (NFPA) codes and standards to assure system functionality. Periodic flushing, system performance testing, and inspections determine whether significant corrosion has occurred in water-based fire protection systems. Many of these systems normally are maintained at required operating pressure and monitored to detect leakage resulting in loss of system pressure immediately for corrective actions. In addition, periodic wall thickness evaluations of fire protection piping on system components by nonintrusive techniques (e.g., volumetric testing) detect loss of material due to corrosion. Inspection of a sample of sprinkler heads required by 10 CFR 50.48 will be guided by NFPA 25 (2002 edition), Section 5.3.1.1.1. NFPA 25 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." This sampling will be repeated every 10 years after initial field service testing.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Fire Water System Program to verify consistency with GALL AMP XI.M27. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Fire Water System Program elements "scope of program," "preventive actions," and "monitoring and trending," are consistent with the corresponding elements in GALL AMP XI.M27. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

The staff asked the applicant to clarify why jockey pumps were excluded from the scope of the Fire Water System Program (Audit Item 152). By letter dated March 24, 2008, the applicant stated that the fire water jockey pumps support standby operation of the fire water system and are conservatively included in the scope of the license renewal and subject to an AMR. The Fire Water System Program manages component aging effects. However, the applicant stated that the jockey pumps are not required for operation of the fire water system to comply with 10 CFR 50.48 and Appendix R. The applicant also stated that testing of the jockey pumps is not required.

The staff reviewed the applicant's response and finds it contrary to the IP3 fire protection SER dated March 6, 1979, which is part of the current licensing basis. That SER reflects the applicant's commitment to implement modifications that conform to the provisions of Appendix A to BTP APCSB 9.5-1. Sections 3.1.5 and 4.3.1.2 of the SER dated March 6, 1979, state in part, "[t]wo 2500 gpm fire pumps, one electric motor driven and one diesel engine driven, will be provided along with two jockey pumps. . . . [t]wo electric jockey pumps [are] provided to maintain pressure on the fire water system . . ." The applicant indicated in the audit question response that the jockey pumps in question are within the scope of license renewal and subject to an AMR but are not required for operation of the fire water system to comply with 10 CFR 50.48 and Appendix R. The applicant's current licensing basis demonstrates that this component was credited to meet the guidance of Appendix A to BTP APCSB 9.5-1. Therefore, the staff considers that the jockey pumps in question should be included within the scope of license renewal pursuant to 10 CFR 54.4(a)(3) because they are required for compliance with 10 CFR 50.48 . The staff agrees that testing is not required for the jockey pump. The staff notes that NFPA Fire Pump Handbook, 1st Edition, Section 2-19, Page 136, states that pressure maintenance devices are not required to be tested for fire protection service. Although the applicant disagrees with the staff's view that the jockey pumps are required for compliance with 10 CFR 50.48, the applicant has included the jockey pumps within the scope of license renewal, and they are subject to an AMR.

During its review, the staff noted that a "cross-connect" of the high pressure fire water system exists between Units 1, 2, and 3 individual fire water supply systems, and asked the applicant if credit has been taken for the use of this capability per the CLB (Audit Item 153). By letter dated March 24, 2008, the applicant clarified that IP2 and IP3 maintain independent fire protection systems and the "cross-connect" is not considered for compliance with IP2 and IP3 fire protection requirements. The IP3 UFSAR states that the IP3 fire protection system was originally designed as an extension of the IP1 fire protection system. After a series of modifications, the IP3 fire protection was made to be independent from the IP1 fire protection system. The staff finds the applicant's response acceptable because it clarified that the cross-connection between units is not credited for compliance with fire protection requirements, and thus, is not subject to an AMR.

Exception. In the LRA, the applicant took the following exception to the GALL Report program element "detection of aging effects":

> NUREG-1801 specifies annual fire hose hydrostatic and gasket inspections. Fire hoses and hose station gaskets are not subject to an AMR and not included in the program.[1]
>
> [1]Fire hoses are periodically inspected, hydrostatically tested, and replaced as required in accordance with plant procedures. Gaskets in couplings are replaced during hose station inspections.

As stated in the footnote, the applicant periodically inspects and replaces hoses and hose gaskets; therefore, they are not subject to an AMR. The applicant treats these components as consumables. The staff determined that, since hose gaskets are replaced on a periodic basis, this meets the guidance in SRP-LR Section 2.1.3.2.2.

The staff recognizes that the applicant's interpretation of these items as consumables (short-lived components) will result in more vigorous oversight of the condition and performance of the component. Therefore, the staff is adequately assured that fire hoses and hose station gaskets used for the fire suppression will be considered appropriately during the period of extended operation.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected" and "acceptance criteria": "[r]evise applicable procedures to include inspection of hose reels for corrosion. Acceptance criteria will be revised to verify no unacceptable sign of degradation."

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire Water System Program element "parameters monitored or inspected" and "acceptance criteria," will be consistent with the GALL AMP XI.M27 program. The staff reviewed the applicant's program procedures to confirm that these elements are consistent with the GALL Report. The staff is adequately assured that this enhancement will adequately manage the effects of aging.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria": "IP3: Revise applicable procedures to inspect the internal surface of the foam-based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion." By letter dated January 17, 2008, the applicant revised this enhancement to remove the reference to IP3. This enhancement now applies to both IP2 and IP3.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire Water System Program elements "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria," will be consistent with the GALL AMP XI.M27 program. The staff reviewed the applicant's program procedures to confirm that these elements are consistent with the GALL Report. The staff is adequately assured that this enhancement will adequately manage the effects of aging.

Enhancement 3. In the LRA, as amended by letter dated December 18, 2007, the applicant committed to implement the following enhancement to program element "detection of aging effects":

> Sprinkler heads for fire water systems required for 10 CFR 50.48 will be replaced or a sample tested using guidance of NFPA 25 (2002 Edition), Section 5.3.1.1.1, before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion are detected in a timely manner.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented, Fire Water System Program element "detection of aging effects," will be consistent with GALL AMP XI.M27 which states that the sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects":

> Wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented, Fire Water System Program element "detection of aging effects," will be consistent with GALL AMP XI.M27 which states that wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry into the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis.

Operating Experience. In addition to the operating experience cited in LRA Section B.1.13, LRA Section B.1.14 stated that visual inspections of fire hose station equipment in September 2005 at IP3 and in November 2006 at IP2 revealed no loss of material on hose station steel parts. One broken sprinkler nozzle was replaced as a result of the IP2 inspection. Detection of degradation followed by corrective action prior to loss of intended function provides confidence that the program will continue to effectively manages aging effects for steel fire water system components.

Further, LRA Section B.1.14 states that flow tests of fire main segments and hydrant inspections during 2006 found no evidence of obstruction or loss of material. Spray and sprinkler system functional tests and visual inspections of piping and nozzles in 2006 found no evidence of blockage or loss of material. Confirmed absence of degradation provides confidence that the program will continue to effectively manage loss of material for fire water system components.

The staff reviewed the above operating experience and also operating experience reports and interviewed the applicant's technical staff and confirmed that the plant-specific operating experience did not reveal any degradation not already bounded by industry experience. The staff also reviewed the IP2 and IP3 operating experience reports, condition reports, and maintenance work orders associated with the corrective actions taken for the identification of signs of degradation of fire protection components. The staff confirmed that the condition reports were closed out by repairs to the degraded fire barriers or performed engineering evaluations for their acceptability. The staff noted that the applicant performs periodic inspections and places identified deficiencies into their corrective action program to ensure appropriate corrective actions are performed in a timely manner.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.13 and A.3.1.13, the applicant provided the UFSAR supplement for the Fire Water System Program. By letter dated December 18, 2007, the applicant revised LRA Section A.2.1.13 to state that "sprinkler heads required for 10 CFR 50.48 will be replaced or a sample tested using guidance of NFPA 25 (2002 edition)." By letter dated January 17, 2008, the applicant revised LRA Section A.2.1.13 to add the following "revise applicable procedures to inspect the internal surface of the foam-based fire suppression tanks." The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.13 and A.3.1.13, the applicant has committed to implement the enhancements prior to entering the period of extended operation (Commitment 8).

Conclusion. On the basis of its audit and review of the applicant's Fire Water System Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justifications and determined that the program s adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Flux Thimble Tube Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.16 describes the existing Flux Thimble Tube Inspection Program as consistent with GALL AMP XI.M37, "Flux Thimble Tube Inspection," with enhancements.

LRA Section B.1.16 states that the Flux Thimble Tube Inspection Program monitors thinning of the flux thimble tube wall, a path for the in-core neutron flux monitoring system detectors and part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. A nondestructive examination (NDE) methodology, eddy current testing or other similar inspection method, monitors for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Flux Thimble Tube Inspection Program to verify consistency with GALL AMP XI.M37. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Flux Thimble Tube Inspection Program elements "scope of program," "preventive actions," "parameters monitored or inspected," and "detection of aging effects," are consistent with the corresponding elements in GALL AMP XI.M37. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program element "monitoring and trending": "[r]evise appropriate procedures to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope."

The staff verified that the applicant included this enhancement in Commitment 9. The "monitoring and trending" program element in GALL AMP XI.M37 recommends that the wear rate projections for flux thimble tubes be based on plant-specific wear data. The staff finds that this enhancement will make the "monitoring and trending" program element in the Flux Thimble Tube Program consistent with the corresponding program element in GALL AMP XI.M37. The staff finds that this is acceptable because the applicant will use the plant-specific wear data to adjust the projected wear values and inspection frequencies if it is determined that the wear rates from the plant specific data are more conservative than the generic wear rate that is recommended in WCAP-12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," January 1991. Thus, the applicant will only use the generic wear rate value if it remains conservative relative to wear rates that are established from the plant-specific data.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "acceptance criteria": "[r]evise appropriate procedures to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results."

The staff verified that the applicant included this enhancement in Commitment 9. In the "acceptance criteria" program element in GALL AMP XI.M37, the staff established the following recommended criteria for acceptance criteria that are used to evaluate flux thimble tube to wear:

> Appropriate acceptance criteria such as percent through-wall wear will be established. The acceptance criteria will be technically justified to provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained. The acceptance criteria will include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies, as applicable, to the inspection methodology chosen for use in the program. Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant's response to Bulletin 88-09 and amendments thereto should be justified.

In response to the NRC Bulletin 88-09 in April 1989, the staff verified that Entergy originally committed to an acceptance criterion of 50 percent allowable throughwall wear in wall thickness of the thimble tubes at IP2 and 60 percent allowable throughwall wear for the corresponding thimble tubes at IP3. However, WCAP-12866[6], established that a thimble tube can safely

[6] Westinghouse WCAP-12866 is a Class 2 Proprietary Westinghouse Report. In NRC Bulletin 88-09, the staff specifically stated, in part, that "each addressee is requested to establish an inspection program to monitor thimble tube performance that includes the establishment, with technical justification, of an appropriate thimble tube wear acceptance criterion."

The 80 percent allowable through-wall wear acceptance criterion established in the report is not considered by the NRC to be proprietary in content because the staff did not intend this type of information to be withheld from the public when it issued NRC Bulletin 88-09. Further, this type of information has been divulged to the general public in the past in other industry correspondence, NRC correspondence, NRC audit reports, and safety evaluations. However, the remaining specific data, equations, and information are considered to be proprietary in content and are operate with up to 80 percent through wall loss, even with considerations of all uncertainties that may occur during an ECT. The staff noted, however, that since 1991, Entergy has used Westinghouse's 80 percent allowable throughwall wear (i.e., a 20 percent minimum wall thickness criterion) as its basis for accepting wear projections prior to the next scheduled outage for the thimble tube examinations.

The staff also noted that Entergy's current program calls for Entergy to perform the ECT examinations of the IP2 and IP3 thimble tubes at scheduled inspection intervals and to record the wall thickness measurements for the thimble. The staff also noted that the applicant's program then calls for Entergy to: (1) use its plant specific wear rate data to project the remaining thimble wall thickness at the next schedule outage in which thimble tube examinations are performed, and (2) compare the projected wall thicknesses to the 20 percent allowable minimum wall thickness criterion that is being relied upon for programmatic acceptance on allowable wear.

The staff has previously accepted the 80 percent allowable throughwall wear acceptance value in the WCAP-12866 because the acceptance criterion was based on conservative burst tests on Westinghouse thimble tube designs that supported this acceptance criterion for the thimble tubes in Westinghouse designed nuclear plants, including IP2 and IP3. The staff also accepted this value because the acceptance criterion includes an additional safety margin on allowable wear in Westinghouse-designed thimble tubes.[6]

The applicant's enhancement of the program will ensure that the acceptance criteria used for the program is proceduralized and justified. The staff has approved the 80 percent allowable throughwall wear acceptance criterion in WCAP-12866 for use because the applicant may justify an acceptance criterion different from this value based on the results of IP2 or IP3 specific wear rate data. Based on this review, the staff finds that this enhancement will make the "acceptance criteria" program element in the Flux Thimble Tube Program consistent with the corresponding program element in GALL AMP XI.M37 and that the enhancement is acceptable.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element "corrective actions":

> Revise appropriate procedures to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate in procedures that flux thimble tubes that cannot be inspected over the tube length and can not be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.

The staff verified that the applicant included this enhancement Commitment 9. In the "corrective actions" program element in GALL AMP XI.M37, the staff established its recommendation that flux thimble tubes out of conformance with the established minimum thimble tube wall thickness acceptable criterion must be either "isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant

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withheld from the public, in accordance 10 CFR 2.390. Therefore, only a general basis on the acceptability of Westinghouse's 80 percent through-wall wear acceptance criterion will be given in this SER.

system pressure boundary," and that thimble tubes approaching this acceptance criterion may be "repositioned." The staff also established that "flux thimble tubes that cannot be inspected over the tube length, that ... [are] ... subject to wear due to restriction or other defect, and that can not be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary."

The staff noted that based on the applicant's use of appropriate Westinghouse documents, the applicant isolates, caps, plugs, withdraws, repositions, or replaces thimble tubes whose wall thicknesses are projected to be less than the minimum wall thickness of 20 percent at the next inspection outage. The staff also noted that the applicant's enhancement of the "corrective actions" program element will incorporate these corrective action criteria. Thus, based on this review, the staff finds that this enhancement will make the "corrective actions" program element in the Flux Thimble Tube Program consistent with the corresponding program element in GALL AMP XI.M37 and that the enhancement is acceptable.

Based on this review, the staff finds that the Flux Thimble Tube Inspection Program, as enhanced by the applicant, is either in conformance with the recommended criteria in GALL AMP XI.M37, or that the enhancements will ensure that use of the generic wear rate and acceptance criterion in WCAP-12866 will be conservative and justified.

Operating Experience. LRA Section B.1.16 states that after flux thimble tube inspections at IP2 in March 1989, an inspection plan used the inspection results and WCAP-12866 methodology.

The applicant's operating experience discussion states that, after flux thimble tube inspections at IP3 in May 1997 and May 2001, a comparison of 1997 to 2001 results for each tube indicating wall loss revealed, in general, that tubes had either no significant increase in wall loss or an increase of 20 percent or less over four years. The applicant's operating experience discussion also indicated that all 2001 recorded wall losses were below the maximum allowed by the WCAP-12866 vendor guidelines and that detection of degradation prior to loss of function indicates that the program is effective in managing loss of material due to wear in these components.

The staff reviewed the "operating experience" program element in the applicant's license renewal basis document for this program but did not find any additional summary details beyond what was originally included and discussed in LRA AMP B.1.16. However, the staff reviewed one ECT test report each for IP2 and IP3 and verified that the ECT test reports confirmed Entergy's claim that it was already periodically performing eddy current inspections of both IP2 and IP3 flux thimble tubes in accordance with the Bulletin 88-09 recommendations.

The staff also verified that, in the spring 2006 IP2 outage, Entergy repositioned all flux thimbles as part of a seal table modification, except for nine thimble tubes that the applicant capped as a more conservative corrective action. The staff verified that Entergy has capped two IP3 thimble tubes based on plant-specific IP3 calculations.

In RAI RCS-2, the staff asked the applicant, in part, to clarify how it performed a condition report review for relevant operating experience related to implementation of this program. The applicant provided its response to RAI RCS-2 in Entergy letter dated June 5, 2008. In this response, the applicant clarified that, with respect to operating experience that is applicable to the Flux Thimble Tube Inspection Program, the applicant took the following two-tiered approach to determine whether there was any applicable operating experience related to the reactor vessel flux thimble tubes at IP2 and IP3:

(1) The applicant conducted interviews of the applicable site program owners at IP2 and IP3 to discuss: (1) program effectiveness, (2) site-specific or generic bases for making any programmatic changes to the program elements of the program, (3) aspects of the program that would demonstrate successful implementation and performance of the program, (4) aspects of the programs that would demonstrate programmatic strengths and weaknesses in the program, and (5) the results of any QA audits, self assessments, or peer review evaluations that were performed on the program

(2) The applicant conducted searches to locate and review applicable inspections, test, and examinations reports for the thimble tubes in order to determine whether the inspections, examinations, or tests had indicated any evidence of aging effects in the thimble tubes. The applicant also conducted applicable keyword searches of its condition report (CR) database in order to locate any IP2 and IP3 flux thimble tubes issues and to ensure that any CRs generated as a result of this search were evaluated and retained for further evaluation of the program.

The applicant stated that inspection results for these components were located in applicable thimble inspection reports, QA surveillance records, and assessment findings. The applicant also stated that the results of these program owner interviews and document searches were documented in the IP "Operating Experience Review Report." The staff noted that the applicant's response to RAI RCS-2 indicated that the applicant had performed an extensive enough review to search for and locate reports or documentation that would provide evidence of age-related aging effects in the IP2 or IP3 flux thimble tubes. Thus, based on the response to RAI RCS-2, as made relative to the Flux Thimble Program, and on the applicant's corrective actions of capping or repositioning to address adverse conditions of thimble tube wear, the staff concludes that the applicant has performed a sufficient review for relative operating experience related to flux thimble tube degradation and that the applicant has provided acceptable evidence that appropriate corrective actions are taken when adverse aging related to thimble tube wear is detected in the components. RAI RCS-2 is resolved with respect to the adequacy of operating experience reviews and corrective actions for flux thimble tubes at IP2 and IP3.

Based on this review, the staff finds that the applicant has been performing its ECT examinations of the IP2 and IP3 thimble tubes to address the experience discussed in NRC Bulletin 88-09 and that Entergy has been taking appropriate corrective action prior to the time when the thimble tube wear is projected to exceeding the applicant acceptance criterion for the program.

Based on this review, the staff confirms that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.15 and A.3.1.15, the applicant provided the UFSAR supplement for the Flux Thimble Tube Inspection Program. The staff reviewed these UFSAR Supplement sections and Commitment No. 9 on the LRA. The staff verified that the UFSAR Supplement summary descriptions in LRA Section A.2.1.15 and A.3.1.15 incorporated the type of elements that are provided in the staff's recommended summary report description for these types of programs, as given in Table 3.1-2 of the SRP-LR. The staff also verified that Commitment 9 of the LRA references that the commitment is applicable to these UFSAR Supplement sections. Based on the review, the staff finds that the information in the UFSAR supplement provides an adequate summary description of the program and meets the requirement in 10 CFR 54.21(d) because the summary descriptions have incorporated the type of element descriptions that are recommended for these type of programs in the SRP-LR and because the UFSAR Supplement summary descriptions appropriately reflect Commitment 9 on the LRA.

Conclusion. On the basis of its audit and review of the applicant's Flux Thimble Tube Inspection Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Masonry Wall Program

Summary of Technical Information in the Application. LRA Section B.1.19 describes the existing Masonry Wall Program as consistent with GALL AMP XI.S5, "Masonry Wall Program," with enhancement.

The Masonry Wall Program manages aging effects so the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. The program visually inspects all masonry walls with 10 CFR 54.4 intended functions. Included components are 10 CFR 50.48-required masonry walls, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components. Structural steel components of masonry walls are managed by the Structures Monitoring Program. Visual examinations of masonry walls are at a frequency to ensure no loss of intended function between inspections.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Masonry Wall Program to verify consistency with GALL AMP XI.S5. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Masonry Wall Program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.S5. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

As documented in the Audit Report, the staff reviewed the program basis documents and confirmed that the Masonry Wall Program is an existing program that manages aging effects for all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. The existing program is the Condition Monitoring of Maintenance Rule Structures which is a program that establishes the requirements for monitoring the various structures at IP2 and IP3 in accordance with 10 CFR 50.65.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to the program element "scope of program": "[r]evise applicable procedures to specify that the IP1 intake structure is included in the program."

During an audit, the staff asked the applicant if a documented seismic qualification basis, in accordance with IE Bulletin 80-11, has been developed for the masonry components of the 1P1 intake structure (Audit Item 62). By letter dated March 24, 2008, the applicant stated that there are no masonry walls in the IP1 intake structure which meet the criteria for inclusion in the site-specific IE Bulletin 80-11 program. Therefore, no seismic qualification basis in accordance with IE Bulletin 80-11 has been developed for masonry walls of the IP1 intake structure. The masonry walls in the IP1 intake structure were included in the Masonry Wall AMP because the IP1 intake structure houses components required for the alternate safe shutdown system, which is credited in the Appendix R safe shutdown analysis. The staff finds that including the masonry walls, located within the IP1 intake structure, in the Masonry Wall Program is acceptable since it provides support for equipment that perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48).

The staff reviewed the proposed enhancement and finds it acceptable because implementation of the enhancement will result in the inclusion of the IP1 intake structure identified by the applicant as within the scope of license renewal in accordance with 10 CFR 54.4(a), which is consistent with the GALL Report.

Operating Experience. LRA Section B.1.19 identifies the following inspection results for masonry walls:

Inspections of the IP2 fan house in 2001 detected cracking and spalling in some walls. These conditions did not affect their structural integrity and were repaired. Slight corrosion of column-to-wall connections did not affect their structural integrity, and was listed for future monitoring.

Inspections of the IP2 fuel storage building in 2003 detected some hairline cracks and loose blocks which were listed for future monitoring.

Inspections of the IP2 control building in 2003 found evidence of water intrusion only in efflorescence on the concrete floor. This condition did not affect the structural integrity of the walls.

Inspections of the IP3 primary auxiliary building, fuel storage building, fan house, and turbine building in 2003 through 2005 noted minor cracking in some walls unchanged from the baseline condition and some leaking seals, which were repaired. A crack in the joint between the fuel storage building and the fan house was noted as acceptable with future monitoring.

Inspections of the city water metering house in 2004 detected some hairline cracks and loose blocks found acceptable but listed for future monitoring.

Inspections of the IP2 turbine building in 2004 detected minor cracks and spalling, which did not affect structural integrity, and were listed for future monitoring.

Inspections of the IP3 control building in 2005 revealed hairline cracks in the battery room walls found acceptable with no effect on structural integrity. These cracks did not require future monitoring.

Inspections of the IP3 fan house in 2006 detected hairline cracks which did not affect the structural integrity of the walls and were listed for future monitoring.

Inspections of the IP3 fuel storage building in 2006 detected minor shrinkage cracking along the mortar joints on the outside of the south wall with no observable change in width since the baseline inspection. These conditions did not affect the structural integrity of the walls.

The applicant concluded that detection of degradation followed by corrective action prior to loss of intended function prove that the program effectively manages cracking of masonry walls and masonry wall joints.

The staff reviewed the program basis document discussion of operating experience. This report discussed the results of past visual examinations of masonry walls at IP2 and IP3. It cites examples of degradation of some masonry walls that occurred in the past and how they were disposition. In some cases hairline cracks were identified and found not to affect structural integrity and in other cases cracks and loose blocks were identified and found not to affect structural integrity, however, they were repaired.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

<u>UFSAR Supplement</u>. In LRA Sections A.2.1.18 and A.3.1.18, the applicant provided the UFSAR supplement for the Masonry Wall Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant has committed to implement the enhancement prior to entering the period of extended operation (Commitment 12).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Masonry Wall Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancement regarding the scope of program element and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes 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 supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 Metal-Enclosed Bus Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.20 describes the existing Metal-Enclosed Bus (MEB) Inspection Program as consistent with the GALL Report AMP XI.E4, "Metal Enclosed Bus," with exceptions and enhancements.

The existing Metal-Enclosed Bus Inspection Program inspects the following non-segregated phase buses:

- IP2/IP3 - 6.9kV bus between station aux transformers and switchgear buses 1/2/3/4/5/6
- IP3 - 6.9kV bus for the gas turbine substation
- IP2 – 480V bus for substation A
- IP2/IP3 – 480V bus between EDGs and switchgear buses 2A/3A/5A/6A

The applicant stated that inspections are for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Inspection of bus insulation is for signs of embrittlement, cracking, melting, swelling, or discoloration which may indicate overheating or aging degradation. The applicant further stated that inspection of internal bus supports is for structural integrity and signs of cracks. Bolted connections are covered with heat-shrink tape or insulating boots per manufacturer recommendations, so a sample of accessible bolted connections is inspected visually for insulation material surface anomalies. Enclosure assemblies are inspected visually for evidence of loss of material.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Metal Enclosed Bus Inspection Program and basis documents for consistency with GALL AMP XI.E4. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Metal Enclosed Bus Program elements "preventive actions," and "monitoring and trending" are consistent with respective elements in GALL AMP XI.E4. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exceptions and their justifications to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff also reviewed the enhancements to determine whether the program will be consistent with the GALL Report AMP XI.E4.

Exception 1. In the LRA, the applicant took the following exception to the GALL Report element "parameters monitored or inspected": "NUREG-1801 specifies this program provides for the inspection of the internal portion of the MEBs. The IPEC program specifies visual inspection of the external surfaces of the MEB enclosure assemblies in addition to internal portions."

Exception 2. In the LRA, the applicant took the following exception to the GALL Report element, "detection of aging effects": "NUREG-1801 specifies this program provides for the inspection of the internal portion of the MEBs. IPEC inspects the MEB enclosure assemblies externally in addition to internal surfaces."

For both exceptions, the applicant stated under Note 1, that "Inspection of the external portion of MEB enclosure assemblies under the Metal-Enclosed Bus Inspection Program assures that effects of aging will be identified prior to loss of intended function. Visual inspections have been proven effective in detecting indications of loss of material."

The GALL Report, Items VI.A-12 and VI-13, refer to the Structure Monitoring Program for inspecting the external of MEB for loss of material due to general corrosion and inspecting the enclosure seals for hardening and loss of strength due to elastomer degradation. In LRA Section B.1.20, the applicant stated that the program attribute of MEB inspection program would be consistent with the program attribute in the GALL Report, Section XI.E4 with an exception. The exception is to inspect MEB enclosure assemblies in addition to internal surfaces using the MEB inspection program. The staff found the exception acceptable because the external of MEBs will be inspected in the MEB Inspection program instead of a separate GALL Structure Monitoring Program. These inspections are the same as those in GALL Structure Monitoring Program.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program element, "scope of program": "[r]evise appropriate procedures to add IP2 480 V bus associated with substation A to the scope of bus inspected."

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria": "[r]evise appropriate procedures to visually inspect the external surface of MEB external enclosure assemblies for loss of material at least once per every 10 years. The acceptance criterion will be no significant loss of material."

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element, "detection of aging effects": "[r]evise appropriate procedures to inspect bolted connections visually at least once every five years or at least once every ten years using thermography."

During the audit and review, the staff noted that the Metal Enclosed Bus Inspection Program, under "program description," only discusses visual inspection, but the enhancements to the existing plant program discussed visual inspection as well as thermography. The staff also noted that the site document for the AMP evaluation, Item 3(b), 4(b), and 6(b) discusses visual inspections. However, the existing plant implementing procedures (etc., 480 V metal enclosed buses) discuss micro-ohm checks. The staff requested the applicant to address the inconsistency among site documents and the LRA. The staff also requested the applicant to provide inspection methods as described in GALL Report AMP XI.E4, or provide a basis for not including these methods in the Metal Enclosed Bus Inspection Program (Audit Item 124). In a letter dated March 24, 2008, the applicant stated that as indicated in LRA Section B.1.20, the "Metal Enclosed Bus Inspection Program" is consistent with the inspection methods described in the GALL Report. The program description in LRA Section B.1.20 will be clarified to describe the alternate tests and inspections discussed in the GALL Report, Section XI.E4. Visual inspections will continue to be used for bolted connections as appropriate. The applicant also stated that the site AMP evaluation report will also be clarified as discussed for LRA B.1.20. The program description, and Items 4(b), and 6(b) will be modified to address the inspection methods besides visual that are discussed in the GALL Report AMP XI.E4. Item 3(b) does not require a change, since this item is consistent with the GALL Report. The inspection methods used in the existing site procedure will be reflected in the site AMP evaluation report.