Progress Energy

Serial: RNP-RA/03-0094

AUG 14 2003

United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261/LICENSE NO. DPR-23

RESPONSE TO LICENSE RENEWAL CONFIRMATORY ITEMS

Ladies and Gentlemen:

By letter dated June 14, 2002, Carolina Power & Light (CP&L) Company, now doing business as Progress Energy Carolinas, Inc. (PEC), submitted an application for renewal of the Operating License for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, which is also referred to as the Robinson Nuclear Plant (RNP).

The NRC staff provided a number of Confirmatory Items by e-mail dated July 14, 2003, from Mr. S. K. Mitra, NRC, to Mr. Roger Stewart, PEC. As a result of these Confirmatory Items, certain RNP license renewal commitments have been revised. These revised commitments are provided in Attachment II to this letter.

Attachment III provides the RNP response to selected Confirmatory Items.

If you have any questions concerning this matter, please contact me.

Sincerely,

Jan F. Lucas

Jan F. Lucas
Manager - Support Services - Nuclear

JSK/jsk

Attachments:
I. Affirmation
II Revised License Renewal Commitments
III. Response to License Renewal Confirmatory Items

A091

Progress Energy Carolinas, Inc.
Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

c: Mr. T. P. O'Kelley, Director, Bureau of Radiological Health (SC)
Mr. L. A. Reyes, NRC, Region II
Mr. C. P. Patel, NRC, NRR
NRC Resident Inspectors, HBRSEP
Attorney General (SC)
Mr. S. K. Mitra, NRC, NRR
Mr. R. L. Emch, NRC, NRR
Mr. R. M. Gandy, Division of Radioactive Waste Management (SC)

AFFIRMATION

The information contained in letter RNP-RA/03-0094 is true and correct to the best of my information, knowledge, and belief; and the sources of my information are officers, employees, contractors, and agents of Progress Energy Carolinas, Inc. I declare under penalty of perjury that the foregoing is true and correct.

Executed on: Aug. 14, 2003

J. W. Moyer
Vice President, HBRSEP, Unit No. 2

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
REVISED LICENSE RENEWAL COMMITMENTS

Item	Commitment	UFSAR Supplement Location	Frequency	Source
25.	ASME Boiler & Pressure Vessel Code, Section XI, Subsection IWL Program enhancements will be made to require supervisors to notify Civil/Structural Design Engineering of the location and extent of proposed excavations of foundation concrete, to require inspection of below-grade concrete when excavated for any reason to monitor for potential effects and to inspect above grade accessible concrete, and include trending requirements for structures based on aggressive ground water. Revised commitment	A.3.1.22	Prior to the period of extended operation	LR Application Appendix B, Section B.3.14 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002 Confirmatory Item 3.5-1
26.	Structures Monitoring Program administrative controls will be enhanced to: (1) include buildings and structures, and associated acceptance criteria, in scope for license renewal but outside the scope of the Maintenance Rule, (2) identify interfaces between structures monitoring inspections of concrete surfaces and the Fire Protection Program requirements for barriers, (3) state clearly the boundary definition between systems and structures, (4) revise administrative controls to provide inspection criteria for portions of systems covered by structures monitoring and require corrective action(s) be initiated for unacceptable inspection attributes, (5) expand system walkdown inspection criteria to include observation of adjacent components, (6) inspect above grade accessible concrete, and (7) revise personnel responsibilities to include providing assistance in evaluating structural deficiencies when	A.3.1.23	Prior to the period of extended operation	LR Application Appendix B, Section B.3.15 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of

	requested by the Responsible Engineer, inspecting excavated concrete to monitor for potential aging effects, and notifying Civil/Structural Design Engineering of the location and extent of proposed excavations, (8) include trending requirements for structures based on aggressive ground water and lake water. Revised commitment			Operating License, dated October 23, 2002 Confirmatory Item 3.5-1
27.	To enhance the Dam Inspection Program, the system monitoring administrative controls will be revised to: (1) identify the "Recommended Guidelines for Safety Inspection of Dams" as the required management program document for the dam, (2) require the responsible system engineer to review the inspection report and initiate corrective actions for any unacceptable attributes, (3) include "Recommended Guidelines for Safety Inspections of Dams" as the applicable inspection guidance in the inspection procedure for RNP, and (4) inspect above grade accessible concrete, (5)) include trending requirements for structures based on aggressive ground water and lake water. Revised commitment	A.3.1.24	Prior to the period of extended operation	LR Application Appendix B, Section B.3.16 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002 Confirmatory Item 3.5-1

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
RESPONSE TO LICENSE RENEWAL CONFIRMATORY ITEMS

Confirmatory Item 2.3.3.9-1:

(Exclusion from an AMR: Refueling water purification pump, piping, and valves necessary for Spent Fuel Pool makeup from the RWST)

The staff requested the applicant to provide adequate justification for the exclusion from an AMR of the refueling water purification pump, piping, and valves necessary for Spent Fuel Pool makeup from the RWST. The staff reviewed the response and relevant licensing basis information. The last licensing action involving a change in the SFPCS design basis was issued as Amendment 69 to Facility Operating License No. DPR-23 on June 8, 1982. The associated license amendment request was forwarded by letter dated December 1, 1980, and stated that the normal spent fuel pool makeup water source, the RWST, has a capacity of 100 gpm, which is more than adequate to replace the water lost following a loss of forced cooling. The associated NRC safety evaluation noted the makeup capability from the RWST and stated that, in the event of SFPCS pump failure, sufficient pump redundancy or makeup would be available to prevent excessive loss of water from the SFP. Maintenance of an adequate SFP cooling water inventory is necessary to prevent an offsite release comparable to that described in 10 CFR Part 100. Therefore, since failure of the non-safety-related makeup supply from the RWST could cause failure of the safety-related spent fuel cooling provided by an adequate coolant inventory, the piping and components necessary to supply makeup water from the RWST should be within the scope of LR in accordance with 10 CFR 54.4(a)(2). The staff found that the applicant has not adequately justified the referred exclusion, and the issue remains as Confirmatory Item 2.3.3.9-1.

Confirmatory Item 2.3.3.9-1 Response:

Progress Energy Carolinas, Inc. (PEC), agrees to include the Spent Fuel Pool (SFP) makeup path from the Refueling Water Storage Tank (RWST) to the SFP within the scope of license renewal. The path from the RWST to the Refueling Water Purification (RWP) pump suction isolation valve, SFPC-805A, located at coordinate B-5 on the license renewal boundary drawing 5379-1485LR, is included in the evaluation boundary shown on the Safety Injection System flow boundary drawing 5379-1082LR, Sheet 2, E-3. License renewal boundary drawings were provided to the NRC by letter dated June 14, 2002. The only portion of the cooling water sub-loop included in the evaluation boundary is the discharge from the SFP Heat Exchanger outlet isolation valve, SFPC-820, to the SFP. For this infrequent operation, the SFP purification system procedure requires that the inlet to the purification loop from the cooling loop, SFPC-798A, be isolated. Additionally, since the scenario suggested above requires loss of cooling, SFP cooling pumps and piping to the SFP Heat Exchanger are not within the evaluation boundary. The purification flow path is within the evaluation boundary as described below (refer to boundary drawing 5379-1485LR):

The path on this drawing begins at the RWST to the RWP pump suction isolation valve, SFPC-805A, at coordinate B-5, to the RWP pump. From this pump, the flow path returns to the SFP Heat Exchanger discharge piping via the SFP cooling demineralizer and filter, purification loop flow element, and through the purification loop outlet valve, SFPC-798B. The bypass piping around both the SFP cooling demineralizer and filter are included in the evaluation boundary.

Note that in letter RNP-RA/02-0159, dated October 23, 2002, regarding the "Discussion of 10 CFR 54.4(a)(2)," the Spent Fuel Pool Cooling (SFPC) system piping and components in the Safety Injection Pump Room (i.e., RWP pump), and Demineralizer Room (i.e., the SFP cooling demineralizer) were determined to be in the zone of influence with safety-related components, and therefore are considered Criterion 2 piping requiring Aging Management Review (AMR).

As a result of the expansion of the evaluation boundary, License Renewal Application (LRA) Table 2.3-15 should also include the SFP cooling demineralizer, SFP filter, and RWP pump, each having an intended function of "Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered." The AMR results for these three additional items should refer to Table 3.3-2, Item 1. The remainder of the piping components in the expanded evaluation boundary are represented by the corresponding items shown in Table 2.3-15, including the corresponding cross-reference to the AMR results. These AMR results are different from GALL, Volume II, Chapter VII, Section A.3, based on material and mechanisms.

The above AMR results are consistent with the AMR results for the Criterion 2 piping and components for the SFPC system as shown in letter RNP-RA/02-0159, "Discussion of 10 CFR 54.4(a)(2)," on page 6 in the third group of systems, and on page 8 in the first group of systems.

A revised LRA Table 2.3-15, reflecting the addition of the SFP makeup flow path from the RWST to the scope of license renewal, is provided below.

Table 2.3-15 COMPONENT/COMMODITY GROUPS REQUIRING AGING MANAGEMENT REVIEW AND THEIR INTENDED FUNCTIONS: SPENT FUEL POOL COOLING SYSTEM

Component/Commodity	Intended Function	AMR Results
Closure Bolting	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered.	Table 3.3-1, Item 13
Flow Orifices/Elements	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered.	Table 3.3-2, Item 1
SFP Cooling Demineralizer	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered.	Table 3.3-2, Item 1
SFP Cooling Filter	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered.	Table 3.3-2, Item 1
Refueling Water Purification Pump	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered.	Table 3.3-2, Item 1
Valves, Piping and Fittings	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. Provide structural support to safety-related components.	Table 3.3-2, Item 1

Note that Valves, Piping, and Fittings, and Closure Bolting are already included in the table.

A revised portion of LRA Table 3.3-2, reflecting the addition of the SFP makeup flow path from the RWST to the scope of license renewal, is provided below.

TABLE 3.3-2 AUXILIARY SYSTEMS AGING MANAGEMENT EVALUATIONS THAT ARE DIFFERENT FROM OR NOT ADDRESSED IN THE GALL REPORT

Component Commodity	Material	Environment (1)	Aging Effect/ Mechanism	Aging Management Program	Discussion
1. Pumps, Valves, Tanks, Piping and Fittings (Primary Sampling, CVCS, Spent Fuel Pool Cooling), SFP Cooling Demeralizer, & Filter, Spent	Stainless Steel	Treated Water (including steam)	Loss of Material from Crevice Corrosion	Water Chemistry Program	The RNP AMR identified crevice and pitting corrosion as potential aging mechanisms. It is assumed that oxygen and contaminants are present such that crevice corrosion is always possible and pitting corrosion is possible if low flow rate conditions exist. The GALL Report notes that stainless steel components are not subject to significant degradation in borated water and that effects of crevice and pitting corrosion on stainless steel components are not significant in chemically treated borated water. (Refer to

Component Commodity	Material	Environment (1)	Aging Effect/ Mechanism	Aging Management Program	Discussion
Fuel Racks, CVCS Heat Exchangers, Pulsation Dampers, Flow Orifices/ Elements, Seal Injection Filter, Seal Return Filter, Volume Control Tank, Valves, Piping, Tubing, and Fittings			Loss of Material from Pitting Corrosion	Water Chemistry Program	the discussion of Systems, Structures, and Components in GALL Sections VII.E.1 and VII.A.3.) Therefore, the Water Chemistry Program alone is considered to be sufficient to manage the aging mechanisms.

Note that the Refueling Water Purification Pump is considered included in the first item "Pumps, Valves, Tanks, Piping and Fittings (Primary Sampling, CVCS, Spent Fuel Pool Cooling)"

Confirmatory Item 3.1.2.2.4-1:

(Issued with regard to the staff's assessment of AMR Item No. 6 of LRA Table 3.1-1, as evaluated in Section 3.1.2.2.4 of the SER)

The staff is concerned that the AMP's credited by the applicant for managing crack initiation and growth of small bore Class 1 piping may be used as a precedent for relieving the applicant of performing the required ASME ISI examinations for the small bore Class 1 piping welds during the period of extended operation for RNP. Therefore, the staff seeks confirmation the applicant will continue to perform the ISI examinations of the small bore Class 1 piping that are required by Section XI of the ASME Boiler and Pressure Vessel Code during the period of extended operation for RNP.

Confirmatory Item 3.1.2.2.4-1 Response:

H. B. Robinson Steam Electric Plant, Unit No. 2, also referred to as the Robinson Nuclear Plant (RNP), will continue to perform Inservice Inspection (ISI) examinations of small bore Class 1 piping as required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel (B&PV) Code during the period of extended operation. Any future exceptions to Code requirements, if proposed, will require NRC staff review in accordance with 10 CFR 50.55a.

Confirmatory Item 3.3.2.4.7-1: (AMP of Radioactive Equipment Drains)

This confirmatory item relates to radioactive equipment drains (REDS). In RAI 2.3.3.7-2, the staff requested the applicant to clarify which portions of this system are included within the scope of license renewal and subjected to an aging management review. In its response dated April 28, 2003, the applicant described the portions of the REDS that are within the scope of license renewal and identified the aging effect of loss of material due to crevice corrosion, pitting corrosion and MIC. In its response to RAI 2.3.3.7-2, the applicant stated that the identified aging effects do not affect the intended function of the REDS, and therefore, do not require management for the period of extended operation. Based on the revision of the information provided in the LRA and the additional information included in the applicant's response to RAI 2.3.3.7-2, the staff requested the applicant to provide additional information to support its conclusion that the identified aging effects do not affect the intended function of the REDS, and therefore, do not required management for the period of extended operation. On June 17, 2003, in a telephone conference, the staff discussed the issue further with the applicant. Subsequent to the telephone conference, by an electronic correspondence dated June 19, 2003, the applicant provided information to support its conclusion on the aging management of REDS. Such explanation has been discussed in Section 3.3.2.4.7.2 of this SER. The staff finds that the applicant has provided adequate information to justify that no AMP is required to manage the aging effects of the REDS because the applicant has demonstrated that leaking and blockage of the REDS are unlikely, the potential flow blockage will be identified and corrected timely by the applicant's routine inspection and other activities, and leakage of the REDS would not adversely impact on the performance of the SSCs. However, the applicant requested to incorporate the supporting explanation into its response to RAI 2.3.3.7-2, which is Confirmatory Item 3.3.2.4.7-1.

Confirmatory Item 3.3.2.4.7-1 Response:

It is anticipated that potential aging effects associated with the REDS piping and components will not cause a loss of the REDS ability to sufficiently drain fire water system water for the following reasons:

1. The stainless steel piping system conducts water into the system by gravity flow from areas of higher elevation to lower elevation at nearly ambient pressure. The system is designed to be self-draining, and to facilitate this feature, horizontal piping is pitched (~¼" per foot).

2. The stainless steel piping and components are normally dry. The REDS operates only intermittently and is self-draining. Although equipment maintenance activities are an on-going process, draining of equipment into the REDS is expected to occur infrequently. Equipment leak reduction is a programmatic process at RNP and

includes such activities as inspections performed by Operations during their rounds, system walkdowns, inspections performed during the performance of routine preventive and corrective maintenance, chemistry sampling, and health physics surveys.

3. Blockage of system components is unlikely because the system is normally dry and the rate of corrosion product formation is expected to be small. Corrosion product formation is not expected to cause flow blockage. Flow blockage from external sources is unlikely. Each floor drain has a slotted stainless steel strainer that is dished with a sediment bucket. The area available for flow through the strainer is ~ 14 in ^{2}, which is larger than the ~ 8 in ^{2} cross sectional area of the 3 inch floor drain piping. The floor drain is thus protected from blockage by large objects, and sediment is trapped before it can enter the system.

4. Operator rounds include Reactor Auxiliary Building room and area checks to identify blocked drains and leaks from pipes, valves, pumps, and tanks. Additionally, abnormal housekeeping conditions, such as loose trash, puddles of water, oil or grease, impeded passageways, blocked access to equipment, and improperly stored equipment, are also identified. Should an unacceptable condition be identified, corrective actions are initiated in accordance with applicable procedures.

5. Decontamination activities include the decontamination of floor drains on an "as needed" frequency. Furthermore, decontamination procedures provide for the use of floor drain socks to prevent solids from entering the REDS during equipment decontamination activities. Prior to installation of the floor drain sock, the following activities occur: 1) a radiological survey of the floor drain is performed, 2) the floor drain is checked for trash/debris, 3) loose trash and/or debris is removed, and 4) the floor drain is wiped out with the appropriate decontamination material.

6. Although degradation of the REDS is not expected to occur, leakage from nonsafety-related systems causing loss of safety-related system intended functions has been examined by the license renewal 10 CFR 54.4(a)(2) analysis. Identification of piping systems and components meeting the criterion of 10 CFR 54.4(a)(2) was performed. No spatial relationship between the REDS and safety-related structures, systems and components (SSCs) was identified such that a REDS failure could adversely impact the performance of safety-related SSCs intended function.

As discussed above, potential aging effects associated with the REDS piping and components will not cause a loss of the REDS ability to sufficiently drain fire water system water. Therefore, no license renewal Aging Management Program is required to manage the identified REDS aging effects.

Additionally, as discussed in conference calls between NRC and RNP on August 13, 2003, the NRC staff noted a discrepancy between the aging mechanism general corrosion, identified in the LRA for the REDS (i.e., Table 3.3-2, line 8), and the aging mechanism microbiologically-induced corrosion (MIC), identified in RAI response 2.3.3.7-2 provided within RNP letter RNP-RA/03-0031, dated April 28, 2003.

After review of the underlying documentation, RNP has concluded that the mechanism, MIC, presented in the RAI response is correct and should be considered to supersede the mechanism presented in the LRA. Stainless steel is not susceptible to general corrosion, while the raw water environment is assumed to have a potential source of MIC. Table 3.3-2, line 8, is amended to read as follows.

8. Piping and Fittings (Radioactive Equipment Drains)	Stainless Steel	Raw Water	Loss of Material from Crevice Corrosion	None	This system was not addressed in the GALL Report. The potential aging effects/ mechanisms that are applicable do not affect the ability of the components to perform their intended functions. Therefore no AMP is required.
			Loss of Material from MIC	None	
			Loss of Material from Pitting Corrosion	None	

Confirmatory Item 3.3.2.4.17-1:

This confirmatory item relates to the aging effects for the materials and environments associated with the components in the dedicated shutdown diesel generator. In RAI 3.3.17-1, the staff requested the applicant to provide a detailed discussion on the AMR performed for the stainless steel valves, piping, tubing and fittings listed in Table 3.3-2, Row Numbers 12, 13, and 23, and explain why the AMR results are different among them. In its response, the applicant stated that the air and gas environments in Row Numbers 12 and 13 include the potential for wetting of stainless steel by untreated water, which is the genesis of the potential aging effects. A detailed explanation of the response has been included in Section 3.3.2.4.17 of this SER. The staff found the referred explanation as appropriate. However, the applicant is requested to provide the above information under oath and affirmation, and this remains as Confirmatory Item 3.3.2.4.17-1.

Confirmatory Item 3.3.2.4.17-1 Response:

The differences in AMR results presented in LRA Table 3.3-2, Items 12, 13, and 23 are provided as follows. The air and gas environments in Items 12 and 13 include the potential for wetting of stainless steel by untreated water, which is the genesis of the potential aging effects. In Item 23, the environment is considered a dry environment which results in no potential aging effects for stainless steel. Some specific examples are listed below for each item.

The diesel component involved in LRA Table 3.3-2, Items 12 and 13, is a single, stainless steel drain valve on the Dedicated Shutdown Diesel (DSD) air start receiver. The compressed air used for starting the DSD has no dryer, so the conditions exist for a build-up of untreated water inside the air receiver and drain piping. The internal surface of the valve is therefore subjected to wetting. The external surface of the same valve is subjected to condensation and was conservatively modeled as being exposed to a wetted environment. An external surface of a stainless steel check valve in the lube oil circulating pump discharge is not exposed to a wetted environment and is therefore being referred to in Item 23. The DSD air start and lube oil subsystems are located inside the DSD enclosure. The references to LRA Table 3.3-2, Items 12, 13, and 23 for valves, piping, tubing, and fittings can be found in LRA Table 2.3-23 at the bottom of page 2.3-56.

The equipment frames and housings in Items 12 and 13 are associated with air handling units. These air handling units have stainless steel drip pans, and as such, their internal environment is subjected to wetting. The external surfaces are exposed to indoors-not air conditioned environments, and are substantially dry, so they are also referred to in Item 23.

The internal environment of the stainless steel check valve in the DSD lube oil circulating pump discharge is included in Item 22 of LRA Table 3.3-2. It too has no aging effects and is not related to the air and gas environments described above.

Confirmatory Item 3.3.2.4.19-1:

This confirmatory item relates to the aging effects for the materials and environments associated with the components in the fuel oil system. In RAI 3.3.17-1, the staff requested the applicant to provide a detailed discussion on the AMR performed for the stainless steel valves, piping, tubing and fittings listed in Table 3.3-2, Row Numbers 12, 13 and 23, and explain why the AMR results are different among them. The air and gas environments in Row Numbers 12 and 13 include the potential for wetting of stainless steel by untreated water, which is the genesis of the potential aging effects. In Row Number 23, the environment is considered a reasonable dry environment which results in no potential aging effects for stainless steel. For the fuel oil system, it has a stainless steel valve and instrumentation tubing, valves, and fittings that are conservatively modeled in a wetted outdoors environment. The fuel oil tank level instrumentation is located outdoors and has components that are near the ground. A detailed explanation of the response has been included in Section 3.3.3.4.19 of this SER. The staff found the referred explanation as appropriate. However, the applicant is requested to provide the above information under oath and affirmation, and this remains as Confirmatory Item 3.3.24.19-1.

Confirmatory Item 3.3.2.4.19-1 Response:

The differences in AMR results presented in LRA Table 3.3-2, Items 12, 13, and 23 are provided as follows. The air and gas environments in Items 12 and 13 include the potential for wetting of stainless steel by untreated water, which is the genesis of the potential aging effects. In Item 23, the environment is considered a dry environment which results in no potential aging effects for stainless steel. Some specific examples are listed below for each item.

The fuel oil system has a stainless steel valve and instrumentation tubing, valves, and fittings that are conservatively modeled in a wetted outdoors environment. The fuel oil tank level instrumentation is located outdoors and has components that are near the ground. Therefore, it was conservatively evaluated as having a potentially wetted external environment. These items account for the LRA Table 3.3-2, Items 12 and 13, referenced for valves, piping, tubing, and fittings from LRA Table 2.3-25. There are also other stainless steel piping components indoors (not air conditioned) that are not in a potentially wetted environment and have no potential aging effects associated with their external surfaces. These items are referring to LRA Table 3.3-2, Item 23, which have no aging effects.

Additional examples are cited in the RNP Response to Confirmatory Item 3.3.2.4.17-1.

Confirmatory Item 3.5-1:

(AMP for below-grade reinforced concrete)

In RAI 3.5.1-3 the staff requested the applicant to provide available RNP ground water chemistry test results including chlorides, sulphate and pH values, and discuss the proposed aging management program, as well as past inspection results of below-grade concrete at RNP, since the below-grade reinforced concrete at RNP is exposed to an aggressive environment (low pH).

In RAI 3.5.1-9 the staff stated that it is unclear as to how the inspection for below-grade containment concrete will be performed by the ASME Section XI, Subsection IWL Program, and requested that additional information, such as the locations, depth, and frequency of soil excavation, related to the AMR of below-grade containment concrete be provided. The applicant provided responses to both RAIs offering commitments that adequately address the staff concerns regarding the aging management of below-grade in-scope concrete structural components at RNP. Because of the slightly acidic RNP groundwater environment, the applicant conservatively assumed existence of an aggressive chemical environment and proposed the plant specific AMPs (an enhanced ASME, Section XI, Subsection IWL Program for containment and an enhanced Structures Monitoring Program for other Category 1 structures) described in Section 3.5.2.2.1.1 of this SER to manage the aging effects of below-grade concrete. The staff finds RAIs 3.5.1-3 and 3.5.1-9 are fully resolved, pending closure of the Confirmatory Item 3.5-1.

Confirmatory Item 3.5-1 Response:

The following summarizes discussions between NRC and PEC on June 16, 2003, in follow-up to RAI B.3.14-1.

The discussion involved assurances that degradation to below-grade concrete exposed to slightly acidic groundwater could be detected. Based on discussions in RAI Clarification O (RAI B.3.14-1) in Attachment III to RNP letter RNP-RA/03-0074, dated June 13, 2003, no significant degradation has been discovered to below-grade or submerged concrete due to slightly acidic groundwater or lake water.

However, RNP has agreed to the following:

Degradation to submerged concrete observed during periodic underwater inspections at the intake structure and the dam spillway will be used as a leading indicator for potential degradation to below-grade concrete structures in the scope of license renewal. Below-grade concrete will be evaluated and/or examined for potential degradation and corrective actions taken as determined by Engineering. This applies to below-grade concrete examined by the Structures Monitoring

Program (SMP) and the ASME Code, Section XI, Subsection IWL Program. Applicable SMP and IWL Program procedures will be enhanced to incorporate these changes.

Groundwater and lake water monitoring results (i.e., for pH, chlorides, sulfates) will be reviewed by Engineering and trended. Increasing aggressiveness of the groundwater and lake water will also be used as a leading indicator for potential degradation to below-grade concrete structures in the scope of license renewal as described above.

Below-grade concrete, when exposed during excavation, already requires notification of Engineering for inspection. However, degradation to below-grade concrete due to aggressive groundwater, when exposed during excavation, will also be used as a leading indicator for potential degradation to other below-grade concrete structures in the scope of license renewal as described above.

Confirmatory Item 4.6.3-1:

(Elimination of Containment Penetration Coolers)

This confirmatory item relates to RAI 4.6.3-2. The staff requested the applicant to describe how the analysis was performed and submit the analysis results of concrete properties at the end of 252 cycles. The staff requested the applicant to clarify whether the conclusion of 252 cycles was obtained from its operating experience in the above response. During a teleconference call on June 10, 2003, the applicant stated it had found an analysis result indicating that the temperature in concrete around the containment penetration would always remain below 200° F. Therefore, the applicant is withdrawing this TLAA item and would submit a new write-up to indicate the withdrawal. Since the applicant's analysis results indicate that the concrete temperature around the containment penetration will always remain below 200° F with the elimination of containment penetration coolers, the applicant informed the staff over the teleconference that it had withdrawn this TLAA issue, and would submit its new write-up accordingly (Confirmatory Item 4.6.3-1). The staff finds the applicant's approach acceptable.

Confirmatory Item 4.6.3-1 Response:

Additional analysis was found which indicates that the temperature of the concrete around containment penetration S15 does not exceed the 200° F allowed by the American Concrete Institute (ACI) Code. Therefore, RNP is withdrawing the Time-Limited Aging Analysis (TLAA) on the Elimination of Containment Penetration Coolers in LRA Section 4.6.3.

Confirmatory Item B.3.11-1:

(Issued with regard to the staff's assessment of the LRA Section B.3.11, Reactor Vessel Surveillance Program, as evaluated in Section 3.1.2.3.4 of the SER)

The withdrawal schedule in WCAP-15805 indicates that in-vessel location for Capsule U was moved sometime within the current life of the plant. Therefore, in a meeting dated May 21, 2003, with the applicant, the staff requested additional clarifying information regarding the elapsed time when Capsule U was moved in the vessel, and what the lead factors were for Capsule U at the different in-vessel locations, and what CP&L's basis was for determining that the projected fluence for Capsule U at its projected time of withdrawal would be indicative of the fluence for the RV shell at 50 EFPY (i.e., at the EFPY projected for the end of the extended period of operation for RNP). During the meeting of May 21, 2003, the applicant informed the staff that it would provide the additional information requested by the staff. The applicant submitted the requested information in an E-mail to the staff dated June 9, 2003. The applicant must formally submit the information in the E-mail of June 9, 2003, onto the "docket" for RNP (i.e., onto docket for Docket No. 50-261) under "Oath and Affirmation." This is Confirmatory Item B.3.11-1.

Confirmatory Item B.3.11-1 Response:

The Capsule U lead factors listed in Table 6-17 of the Capsule X report, i.e., WCAP-15805, can be developed from information provided in WCAP-15805, Tables 6-1 and 6-2. Note that WCAP-15805, "Analysis of Capsule X from the Carolina Power and Light Company H. B. Robinson Unit 2 Reactor Vessel Radiation Surveillance Program," was submitted to the NRC by letter dated April 25, 2002.

Capsule U was irradiated in the 30 degree capsule location for fuel cycles 1 through 8, and in the 10 degree capsule location for cycles 9 through 20. From Table 6-1, the fluence accrued by Capsule U during cycles 1 through 8 was 9.59×10^{18} n/cm^2, and the subsequent fluence accrued during cycles 9 through 20 was $[5.66 \times 10^{19} - 2.73 \times 10^{19}] = 2.93 \times 10^{19}$ n/cm^2. Thus, the total exposure of Capsule U through the first 20 fuel cycles was $[9.59 \times 10^{18} + 2.93 \times 10^{19}] = 3.89 \times 10^{19}$ n/cm^2. From Table 6-2, the corresponding maximum exposure of the pressure vessel for cycles 1 through 20 was 2.76×10^{19} n/cm^2.

Therefore, at the end of cycle 20, the composite lead factor for Capsule U was computed to be $[3.89 \times 10^{19}]/[2.76 \times 10^{19}] = 1.41$, as reported in Table 6-17.

For future operation, it was assumed that core power distributions averaged over cycles 16 through 21 would be characteristic of reactor operation and that Capsule U would remain in the

10 degree capsule location. Given these assumptions, the average neutron flux at the capsule location was computed from the data in Table 6-1 as follows:

Capsule Exposure Rate = $[5.90\text{x}10^{19} - 4.17\text{x}10^{19}]/[(21.78\text{-}13.95)\text{x}(365.25\text{x}24\text{x}3600)] = 7.00\text{x}10^{10}$ n/cm^2-s

The corresponding maximum vessel flux was determined as:

Vessel Exposure Rate = $[2.87\text{x}10^{19} - 2.01\text{x}10^{19}]/[(21.78\text{-}13.95)\text{x}(365.25\text{x}24\text{x}3600)] = 3.48\text{x}10^{10}$ n/cm^2-s

Therefore, for the future irradiation periods, the capsule will accrue neutron exposure at a rate $[7.00\text{x}10^{10}]/[3.48\text{x}10^{10}] = 2.02$ greater than the maximum exposure location on the pressure vessel as listed in Table 6-17. This lead factor applicable solely to the 10 degree location is greater than the composite lead factor applicable to the first 20 cycles of irradiation.

In practical terms, this means that, due to the past capsule exposure in a low lead factor location followed by the current and future exposure in a higher lead factor location, the composite lead factor for Capsule U will, over time, increase from the end of cycle 20 value of 1.41 toward the projection lead factor for the 10 degree location (2.02). This is due to the fact that the longer the capsule remains in the 10 degree location, the fluence accrued in the 30 degree location becomes less of a contributor to the overall fluence. For very long exposures, the composite lead factor will approach the value of 2.02.

The actual lead factor for any future cycle can be determined from the current exposure, the projected exposure rates, and the future cycle lengths.

Confirmatory Item B.4.2-1:

(Issued with regard to the staff's assessment of the LRA Section B.4.2, Thermal Aging of Cast Austenitic Stainless Steel Program, as evaluated in Section 3.1.2.3.7 of the SER)

The staff seeks confirmation that, although an LBB flaw tolerance evaluation has been performed for the extended period of operation for RNP (as given in WCAP-15628), the applicant will continue to perform those inservice inspection (ISI) examinations for the primary coolant loop piping, valve, and pump casings that are required by Table IWB-2500-1 of Section XI to the ASME Boiler and Pressure Vessel Code, unless relief has been granted by the NRC under applicable provisions in 10 CFR 50.55a from meeting the staff's ISI requirements of 10 CFR 50.55a(g)(4). If relief has been granted from any of the required ISI examinations for the primary coolant loop piping, valve, or pump casings, the staff seeks confirmation of the applicable NRC staff safety evaluation granting this relief and the specific ISI examination requirements for which relief has been granted. The staff also seeks confirmation that the UFSAR Supplement summary description will be amended to reflect the information in the Applicant's response to this confirmatory item. This is Confirmatory Item B.4.2-1.

Confirmatory Item B.4.2-1 Response:

The UFSAR Supplement summary description is amended to include the following:

> "RNP will continue to perform Inservice Inspection (ISI) examinations for the primary coolant loop piping, valve, and pump casings as required by Table IWB-2500-1 of Section XI to the ASME Boiler and Pressure Vessel Code, unless relief has been granted by the NRC under applicable provisions in 10 CFR 50.55a from meeting the staff's ISI requirements of 10 CFR 50.55a(g)(4).
>
> Relief has been granted for several ISI requirements as documented in NRC letter dated September 26, 2002. The granted relief has been authorized for the Fourth Ten-Year Interval for RNP, which began on February 19, 2002, and is scheduled to end on February 18, 2012."