L. M. Stinson (Mike)
Vice President

Southern Nuclear Operating Company, Inc.
40 Inverness Center Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.5181
Fax 205.992.0341

SOUTHERN COMPANY
Energy to Serve Your World℠

March 5, 2004

Docket Nos.: 50-348
50-364

NL-04-0318

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Joseph M. Farley Nuclear Plant Units 1 and 2
Application for License Renewal –
January 22, 2004 and February 3, 2004 Requests for Additional Information

Ladies and Gentlemen:

This letter is in response to your letter dated February 3, 2004 requesting additional information for the review of the Joseph M. Farley Nuclear Plant, Units 1 and 2, License Renewal Application. Also included are responses to two Requests for Additional Information (RAIs) contained in your letter of January 22, 2004. These responses are provided in Enclosure 1. Note that your letter dated February 13, 2004 stated RAI 3.1-2 should have been omitted from the February 3, 2004 letter and therefore is not part of this response.

Mr. L. M. Stinson states he is a vice president of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

If you have any questions, please contact Charles Pierce at 205-992-7872.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

L. M. Stinson
Vice President, Farley

Sworn to and subscribed before me this 5th *day of* March, *2004.*

Maria H. Bui
Notary Public

My commission expires: 06-07-05

A099

LMS/JAM/slb

Enclosure: Responses to January 22, 2004 and February 3, 2004 Requests for Additional Information, Joseph M. Farley Nuclear Plant, Units 1 and 2

cc: Southern Nuclear Operating Company
Mr. J. B. Beasley Jr., Executive Vice President
Mr. D. E. Grissette, General Manager – Plant Farley
Document Services RTYPE: CFA04.054; LC# 13974

U. S. Nuclear Regulatory Commission
Ms. T. Y. Liu, License Renewal Project Manager
Mr. L. A. Reyes, Regional Administrator
Mr. S. E. Peters, NRR Project Manager – Farley
Mr. C. A. Patterson, Senior Resident Inspector – Farley

Alabama Department of Public Health
Dr. D. E. Williamson, State Health Officer

Joseph M. Farley Nuclear Plant Units 1 and 2

Application for License Renewal-

Responses to January 22, 2004 and February 3, 2004
Requests for Additional Information

RAI 3.1-1

LRA Table 3.1.1, item 3.1-37 states:

> "The FNP AMR results are consistent with the intent of this summary item, with the exception that SNC applies a higher threshold value for neutron fluence effects on stainless steels than does NUREG-1801."

However, this exception is not specifically discussed in Section B.5.1.3 of LRA Appendix B.5.1, "Reactor Vessel Internals Program." Please confirm that this exception is applicable to Appendix B.5.1, identify the higher threshold value for neutron fluence effects, and justify the use of this higher value for the LRA of Farley.

Response:

LRA Table 3.1.1, item 3.1-37 is concerned with loss of fracture toughness due to thermal aging, neutron irradiation embrittlement, and void swelling for reactor vessel internals CASS components.

SNC confirms that this fluence threshold value exception referred to in the discussion column for item 3.1-37 is applicable to FNP LRA Appendix B.5.1, "Reactor Vessel Internals Program."

SNC applies a threshold value for neutron fluence effects on stainless steels of $1x10^{21}$ n/cm^2 ($E > 0.1$ MeV). This value is consistent with WCAP 14577-A Revision 1, "License Renewal Evaluation: Aging Management for Reactor Internals," which has been accepted by the Staff. NUREG-1801 Section XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," utilizes a fluence threshold of $1x10^{17}$ n/cm^2 ($E > 1.0$ MeV) for irradiation effects on CASS components. No fluence threshold value is provided in NUREG-1801 Section XI.M16, "PWR Vessel Internals."

Regardless of the specific fluence threshold value used, reactor vessel internals components with the highest neutron fluences are considered to have the highest susceptibility to irradiation induced degradation and therefore are the leading locations for inspection. The FNP Reactor Internals Program provides for inspection and monitoring of these leading locations and therefore provides reasonable assurance that the aging effect will be detected and adequately managed during the period of extended operation.

RAI 3.2-2

LRA Table 3.2.2-3 states that loss of material in an oil environment was determined not to be an aging effect requiring management for the carbon steel oil cooler shell and the copper alloy tubes for the high head safety injection pump in the emergency core cooling system. The GALL report recommends a plant-specific aging management program for loss of material due to general, pitting, and crevice corrosion and microbiologically induced corrosion (MIC) in carbon steel components exposed to lubricating oil that may be contaminated with water. Similar aging effects (except general corrosion) are possible for copper alloy. The NRC staff considers a periodic inspection program appropriate to manage this aging effect. For the oil cooler shell and tubes in the emergency core cooling system exposed to an oil environment, the applicant is requested to provide aging management for loss of material due to general (carbon steel), pitting, and crevice corrosion and MIC, or provide justification for not managing this aging effect.

Response

The SNC position is that lubricating oil systems at FNP are assumed to be free of water contamination as their initial condition. Lubricating oil systems are typically closed systems that have little potential for ingress of contaminants unless a component failure occurs. License renewal does not assume component failures as a means to establish the conditions necessary for aging to occur. For example, tube failures in lubricating oil coolers are not assumed because the cooling water side of the tubes is age-managed. Therefore, water contamination of lubricating oil is event driven, and would be addressed by corrective maintenance. For License Renewal purposes, lubricating oil is therefore assumed to be free of water contamination.

Although they are not credited for aging management, other site activities provide added assurance that lube oil is not contaminated with water. Oil levels for the high head safety injection/charging pumps are visually checked every shift for proper level and for visual evidence of contamination (milky appearance of oil or visible oil/water boundary). The oil is sampled every six months and is changed based on the results of the sample analysis. Oil levels and condition are also checked during quarterly pump surveillance testing.

Appendix A of the EPRI Mechanical Implementation Guideline and Mechanical Tools, Rev. 3 (EPRI TR-1003056) indicate that significant corrosion is only expected where water can settle or pool. However, since water contamination is not expected, settling or pooling should not occur; therefore, lubricating oil systems are not susceptible to loss of material due to general corrosion, pitting, crevice corrosion or MIC. FNP operating experience supports this conclusion. In addition, the SNC position of no aging effect requiring management for a lubricating oil environment with no water contamination is consistent with that of other applicants and found acceptable to the NRC Staff.

RAI 3.2-3

LRA Table 3.2.2-3 states that the copper alloy oil cooler tubes for the high head safety injection pump in a closed cycle cooling water environment will be managed for loss of material using the Water Chemistry Control Program and the One-Time Inspection Program. For this material type and environment, the staff considers selective leaching to be aging effects requiring management. The applicant is requested whether selective leaching is considered to be an aging mechanism rather than an aging effect for the tubes. If so, describe the type of inspections used by the One-Time Inspection Program to detect selective leaching in the tubes. Also, list any other aging mechanisms for this item and discuss if the One-Time Inspection Program provides verification that the aging effect is not occurring.

Response:

The High Head Safety Injection Pump lubricating oil cooler tubes are not considered to be susceptible to selective leaching. These tubes are fabricated from admiralty brass. The major constituents of admiralty brass are Copper (70%), Zinc (29%), and Tin (1%). The presence of 1% Tin in admiralty brasses has the effect of increasing resistance to, or inhibiting, selective leaching (dezincification) (Ref. EPRI TR-1003056, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3). In the non-aggressive lubricating oil and closed-cycle cooling water environments to which these tubes are exposed, selective leaching is not expected to be a significant issue for inhibited brasses.

The aging mechanisms applicable to the High Head Safety Injection Pump lubricating oil cooler tubes in a closed cycle cooling water environment are pitting, crevice corrosion, and microbiologically influenced corrosion. As stated in LRA Table 3.2.2-3, these tubes are included within the FNP One-Time Inspection Program scope. The FNP One-Time Inspection Program will develop a set of bounding inspection locations drawn from the population of susceptible component locations in systems crediting the One-Time Inspection Program. Inspections will be included to verify that significant localized corrosion of brass components is not occurring.

RAI 3.2-4

The GALL report recommends further evaluation of programs to manage the loss of material due to pitting and crevice corrosion to verify the effectiveness of the Water Chemistry Control Program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is progressing very slowly so that the intended function will be maintained during the period of extended operation. LRA Tables 3.2.2-1, 3.2.2.-2, and 3.2.2-3 list various stainless steel components in a borated water environment with the aging effect being loss of material. The aging management program for these components is the Water Chemistry Control Program; however, the One-Time Inspection Program is not credited to verify the effectiveness of the Water Chemistry Control Program. The applicant is requested to explain why a one-time inspection is not performed to determine the effectiveness of the Water Chemistry Control Program. Also, state the aging mechanisms for the loss of material.

Response

NUREG-1801, section XI.M2, only recommends one-time inspection "... as identified in the GALL report ...," SNC has not identified any NUREG-1801 recommendation for a one time inspection of stainless steel ESF system group components exposed to a borated water environment.

NUREG-1801 does identify that loss of material due to pitting and crevice corrosion is not an aging effect/mechanism requiring management for stainless steel components exposed to a borated water environment. Specifically, several sections of NUREG 1801 (e.g., sections V.D1, VII.A3, VII.E1) conclude that stainless steel components are not subject to significant general, pitting, and crevice corrosion in a borated water environment; therefore these aging mechanisms are not included in NUREG-1801 for this material and environment combination.

NUREG-1801 does address stress corrosion cracking of stainless steel ESF system group components exposed to a borated water environment; however NUREG-1801 does not recommend a verifying one-time inspection in any of these ESF line items.

SNC agrees that in the normal borated water environment, stainless steel components are not subject to significant general, pitting, and crevice corrosion. SNC conservatively identified loss of material (due to pitting and crevice corrosion) as a potential aging effect that is adequately managed by the Water Chemistry Control Program without supplemental one-time inspections. Our rationale follows.

Localized corrosion of stainless steels is not a long term, linearly progressive process like general corrosion of carbon steels. Stainless steel components derive their corrosion resistance from the thin, tightly adherent, passive chromium oxide layer that forms at the component surface. If the environmental conditions are not sufficiently aggressive to penetrate this oxide layer, then no significant corrosion is expected to result. Conversely, If the environment is sufficiently aggressive to disrupt the oxide layer then localized corrosion may be expected to proceed at a significant rate.

For austenitic stainless steels, penetration of the passive chromium oxide layer and subsequent corrosion has been shown to be principally related to the oxidizing nature of

the environment and the presence of specific detrimental ionic species known to interfere with the passivation process; most notably chlorides, sulfates, and fluorides. Appendix A of the EPRI Mechanical Implementation Guideline and Mechanical Tools, Rev. 3 (EPRI TR-1003056) indicates that localized corrosion of stainless steels exposed to borated water is not a significant concern when dissolved oxygen concentrations are less than 100 ppb and concentrations of detrimental ionic species are less than 150 ppb.

The FNP Water Chemistry Control Program is implemented consistent with the EPRI PWR Primary Water Chemistry Guidelines. This chemistry control program provides for both a strongly reducing environment via the addition of oxygen scavengers and strict control of detrimental ionic species. These controls limit both dissolved oxygen and detrimental ionic species concentrations to values well below those specified by the EPRI Mechanical Tools.

FNP and industry wide operating experience confirm that pitting and crevice corrosion have not been an issue of concern. FNP inservice inspections performed in accordance with Section XI of the ASME Code include numerous inspection locations consisting of the borated water/stainless steel environment and material combination. Inspection locations include sections of stagnant piping such as ECCS accumulator injection lines, containment ECCS sump suction lines, and safety injection lines. These inservice inspections perform examinations of pipe welds and component internal surfaces. The examinations would identify crevice corrosion and pitting. The inservice inspections have been performed for many years, and do not indicate a history of, or susceptibility to, loss of material due to pitting or crevice corrosion.

For the reasons described above, one-time inspections of ESF components to verify the effectiveness of the Water Chemistry Control Program are unnecessary.

RAI 3.2-5

LRA Table 3.2.2-3 lists loss of material for the carbon steel encapsulation vessel in an air and gas (wetted) environment as being managed by the One-Time Inspection Program. Section 3.0.4 of the LRA defines an air and gas (wetted) environment as containing significant amounts of moisture where condensation or water pooling may occur and such components in this environment include cooling units and non-dried air system low points. The GALL report recommends a one-time inspection in cases where either 1) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or 2) an aging effect is expected to occur very slowly. The staff does not consider a one-time inspection appropriate to manage this aging effect for a carbon steel component. The applicant is requested to provide a periodic inspection aging management program for this component or to provide adequate basis for performing a one-time inspection.

Response

The internal environment of the encapsulation vessels is incorrectly shown in Table 3.2.2-3. The correct internal environment is air/gas which is defined as containing air that is similar in temperature and moisture content to ambient air conditions located throughout the plant, with no significant condensation expected. The internal air/gas environment of the encapsulation vessels is stagnant and at the same temperature as the surroundings such that condensation is not expected. Thus, there are no significant amounts of moisture available where condensation or water pooling could occur. The One Time Inspection Program is correctly utilized for aging managing the internal surfaces of the encapsulation vessels exposed to an air/gas environment.

The encapsulation vessels are located in the containment sump suction lines and are described in FSAR Section 6.2.2.2.1. These vessels are connected to suction line concentric guard pipes and provide watertight enclosures for the first motor operated isolation valves in the suction lines off the containment sump. They are designed to withstand the containment design pressure in addition to the head of water present in the containment sump at the end of the injection phase. The arrangement of encapsulation vessels and guard pipes assures that the integrity of the recirculation system is not impaired in the unlikely event of leakage from the suction pipe during long term recirculation.

Each encapsulation vessel is configured with a bolted flange such that the top portion can be removed for access to the motor operated valve contained within. The vessel is free standing on a support collar such that it supports its own weight and is not supported by the internal piping/valve or the attaching guard pipe.

RAI 3.2-6

LRA Table 3.2.2-3 lists loss of material and cracking as aging effects requiring management for the flow orifice/element, but does not list erosion. The staff considers erosion a possible aging effect requiring management for flow orifice/elements. The applicant is requested to describe the flow orifice/element, its location in the system, and why erosion is not considered to be an aging effect requiring management.

Response

These stainless steel flat-plate orifices are used for both flow measurement and flow restriction and do not experience significant pressure drops. They are exposed to chemically treated water that does not contain particulates. EPRI TR-1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools", Rev. 3, Section 3.1.6 states "material loss because of erosion is possible only if the fluid contains particulates in the fluid stream that impinges upon the surface of the metal. Treated water chemistry and filtration requirements typically preclude the buildup of particulates that could contribute to abrasive erosion of carbon, low-alloy, wrought austenitic stainless steel, cast iron, CASS, copper alloys and nickel-based alloys." Stainless steel materials are not generally susceptible to any form of erosion, erosion-corrosion, or flow accelerated corrosion in a borated water environment. Even without chemistry controls, the closed nature of the system and the tightly adherent oxide layers formed by these austenitic materials preclude the possibility of any significant erosion of the material. Therefore, erosion of these stainless steel flat-plate orifices in a borated water environment is not an aging effect requiring management in FNP aging management reviews.

The flat-plate orifices are located in piping runs in numerous locations. For example, flat-plate orifices associated with flow instrumentation (FE940 & FE943) are located in the HHSI flow paths (D175038L sheet 1, orifices FE940 & FE943, approximate coordinates E-8 and G-7 respectively).

It is noted that the charging/SI pump mini-flow orifices experience significant pressure drops and are constructed of a long spool of stainless steel pipe with a relatively small ID. This orifice design dissipates energy over the entire length of the spool piece, thus greatly reducing the potential for significant loss of material. However, these specially designed orifices are called out as a separate component type in Table 3.2.2-3 and are age managed by both the Water Chemistry Control Program and the One-Time Inspection Program.

RAI 3.3-3

Loss of material and fouling are listed in LRA Table 3.3.2-5 as aging effects that require aging management for the open-cycle cooling water system components listed below. However, the GALL report (NUREG-1801) does not identify fouling as an aging effect applicable to these components. Fouling is generally an aging effect for components with intended function of heat transfer, not pressure boundary. Explain how fouling is related to the pressure boundary intended function of these components. Identify and describe the program that is credited for detection, prevention, and monitoring of the aging effect due to fouling for these components.

- CCW heat exchanger's channel head and tube sheet
- Containment and ESF room coolers' channel heads
- Air compressor lube oil cooler's tubesheet and channel head
- Air compressor intercooler and aftercooler and bleed-off air coolers' shells, tubesheet, and channel head

Response

Fouling is not related to the pressure boundary intended function of the channel heads, shells, and tubesheets for the heat exchangers and coolers listed, and therefore should not have been identified in LRA Table 3.3.2-5 as an aging effect requiring management for these components. There are no other impacts to LRA Table 3.3.2-5 resulting from removal of fouling as an aging effect requiring management for these components.

SNC concurs that, in license renewal aging management reviews, fouling is generally an aging effect for components with an intended function of heat transfer, not pressure boundary. For the FNP LRA, SNC defines the aging effect of fouling as it pertains to loss of heat transfer performance. For the open-cycle cooling water system, fouling is an aging effect requiring management for heat transfer tubing in a raw water environment. The Service Water Program, described in Section B.4.4 of the LRA, is credited for managing this fouling.

RAI 3.3-4

Column 8 of Table 2 (LRA Tables 3.3.2-x), refers to Item 3.3.1-29 of Table 1 for many auxiliary system components with loss of material aging effects due to selective leaching of carbon steel, copper alloy (brass), and stainless steel materials. The discussion column of Table 1, Item 3.3.1-29 addresses only CCW pumps fabricated from carbon steel. Provide additional information on how selective leaching is addressed for copper alloy (brass) and stainless steel materials in the components of the auxiliary systems (OCCW, CCW, EDG, etc.) Further, describe the credited FNP program for the detection of the selective leaching of materials and compare it with GALL AMP X1.M33 for consistency determination.

Response

Carbon steel and stainless steel are not susceptible to selective leaching in the auxiliary systems environments; therefore, the references in LRA Tables 3.3.2-x to "Table 1 Item" 3.3.1-29 in column 8 for carbon steel and stainless steel components are incorrect.

The incorrect reference to "Table 1 Item" 3.3.1-29 for carbon steel components was a result of "automatically" populating column 8 using the NUREG-1801 Volume 1 tabulations. The "Table 1 Items" used in the LRA are the same as the summary items used in the Standard Review Plan (NUREG-1800) and in NUREG-1801 Volume 1. In NUREG-1801 Volume 1, the specific NUREG-1801 Volume 2 items (LRA Tables 3.3.2-x column 7) associated with each summary item are listed. The "Table 1 Item" column (column 8) in the LRA Tables was automatically populated in the LRA Tables based on the NUREG-1801, Volume 1 Tables. In NUREG-1801 Volume 2, several Auxiliary Systems items addressed more than one material (e.g., carbon steel, copper alloys) with only one of the materials having an aging effect of selective leaching. This resulted in the Volume 2 item being associated with two (2) Volume 1 summary items, however the applicability of selective leaching ("Table 1 Item" 3.3.1-29) is dependent on which material is applicable. This "limited applicability" of the Volume 2 item was not included in the NUREG-1801 Volume 1 summary listing.

For example, in LRA Table 3.3.2-5, the CCW Heat Exchanger (shell) line item is listed with a material of carbon steel, internal environment of closed cooling water, and aging effect requiring management of Loss of Material. This is a match for NUREG-1801, Volume 2, Chapter VII, Item C1.3-a which includes carbon steel, aluminum-bronze, copper-nickel, and aluminum brass materials. In NUREG-1801 Volume 1, item VII.C1.3-a is listed twice in Table 3 for different summary items, once for loss of material due to general, pitting, crevice corrosion, etc., and once for selective leaching. Since the LRA tables were automatically populated by cross-referencing the Volume 2 item number with the Volume 1 item number, both references to the Volume 1 items (3.3.1-17 and 3.3.1-29) appear every time Volume 2 Item VII.C1.3-a was listed. This is true even though 3.3.1-29 may not be applicable to the specific component, depending on the material of construction. This effect occurred for several systems, as noted in the RAI.

The following table summarizes the components in the 3.3.2-x Tables which are susceptible (potentially) to loss of material due to selective leaching.

LRA SYSTEM	COMPONENT	MATERIAL
OCCW	CCW HX Tubes	Copper alloy
EDG	HX Tubes, Tubesheets	Copper alloy
FP	Fire Hydrants	Cast iron
FP	Hose Station Nozzles and Hose Connections	Cast iron, copper alloy
FP	Piping	Cast iron, copper alloy
FP	Pump Casings	Cast iron
FP	Sprinkler Heads	Copper alloy
FP	Strainer Shells	Cast iron, copper alloy
FP	Valve Bodies	Cast iron, copper alloy
OCCW	CTMT Cooler and ESF Room Cooler Channel Heads and Tubes	Copper alloy
OCCW	Strainer Shells	Cast iron

FNP credits the One-Time Inspection Program for detection of selective leaching in potentially susceptible materials. The One-Time Inspection Program is described in LRA Appendix B, Section B.5.5. LRA Section B.5.5.2 states that the FNP One-Time Inspection Program is a new program that will include elements to make it consistent with the NUREG-1801 Aging Management Program XI.M.33 for detection of selective leaching.

RAI 3.3-5

Equipment frames and housings (crankcase ventilation) is defined in LRA Table 3.3.2-15 as being consistent with GALL (item VII.H2.4-a) for material, environment, aging effects and aging management program. However, the GALL item is for a different component. The material of the EDG equipment frames and housings in LRA Table 3.3.2-15 is cast iron in a wetted air environment. The material for GALL item VII.H2.4-a is carbon steel in an environment with "hot diesel engine gases containing moisture and particulate." Therefore, the material and environment for the equipment frames and housings are different from the GALL (item VII.H2.4-a) material and environment. Please justify the conclusion of being consistent with GALL, determine whether the One-Time Inspection Program is applicable to the equipment frames and housings, and make any necessary changes to the Table, if required.

Response

In Section 3.0.2 of the LRA, SNC stated the GALL line item comparison is based fundamentally on the intent to manage aging. As stated in Section 3.0.3.4.2 of the LRA, "The aging management line item comparison is performed with the goal of illustrating the best possible match between an FNP LRA Table 2 line item and a NUREG-1801 Volume 2 aging management line item. The primary emphasis is placed on finding a similar aging management strategy for the same material and environment combination. The aging management strategy comparison is provided as a review aid only."

The cast iron component type in question, "equipment frames and housings (crankcase ventilation)," is part of the crankcase exhaust system on the emergency diesel generators. In LRA table 3.3.2-15, the cast iron crankcase component type is compared to GALL item VII.H.2.4-a with a note C. Note C indicates the component is different, but is consistent with GALL for material, environment, and aging effect, and the aging management program (AMP) is consistent with the NUREG-1801 AMP. SNC agrees the cast iron material is technically different from the GALL item's carbon steel material and therefore the use of Note C is a source of confusion. However, the GALL comparison information is provided only as a review aid.

Below is a discussion of the attributes (i.e., material, environment, aging effect, and AMP) classified as consistent with GALL item VII.H.2.4-a.

- Material
  NUREG-1801 identifies loss of material due to general, pitting and crevice corrosion for carbon steel in the hot diesel engine exhaust gas environment (GALL item VII.H.2.4-a). Cast iron is generally more corrosion resistant than carbon steel, but was determined to be subject to loss of material from corrosion in this environment. A plant-specific note should have been included in the LRA for this line item indicating "the material is not the same as the associated NUREG-1801 Volume 2 Item but is similar and has the same aging effect in this environment."

- Environment
  These cast iron crankcase components contain the exhaust of the diesels, which is most closely represented by the internal environment, "Air/Gas (Wetted)," in the SNC LRA for FNP. The internal environment of the

crankcase exhaust components is the same as the environment for GALL item VII.H2-4a. A plant-specific note should have been included in the LRA to further describe the environment as "Air/Gas (Wetted) including hot diesel engine gases containing moisture and particulate."

- Aging Effect
  In the presence of an Air/Gas (Wetted) environment, cast iron can experience a loss of material. This is the same aging effect requiring management shown in GALL for item VII.H2-4.

- Aging Management Program
  NUREG-1801 recommends a plant-specific AMP. SNC has chosen a plant specific program, the One Time Inspection (cf. LRA section B5.5), to evaluate the loss of material on this component. A review of FNP operating experience performed for development of the FNP license renewal application did not identify any failures of the cast iron components in the EDG exhaust system due to loss of material. Cast iron components are generally of robust design. In addition, the emergency diesels operate sparingly (primarily only for surveillances) therefore actual operating time with exhaust gases is limited. The One Time Inspection (OTI) Program will be utilized to confirm aging management (other than OTI) is not required for this aging effect.

In summary, no change to the aging management review results (e.g., aging effect and aging management program) in Table 3.3.2-15 is required.

RAI 3.4-1

For various stainless steel components in LRA Table 3.4.2-x

(a) Cracking is identified as the aging effect for various stainless steel components in steam or treated water environments. The applicant credits the Water Chemistry Control Program to manage this aging effect. Since stainless steels are susceptible to cracking in these types of environments, the applicant is requested to justify why the Water Chemistry Control Program without an inspection program to verify that cracking is not occurring is adequate to manage this aging effect, or to provide an inspection program.

(b) Loss of material is identified as the aging effect for various stainless steel components in treated water environments. The applicant credits the Water Chemistry Control Program to manage this aging effect. Stainless steels are susceptible to loss of material in this type of environment and the GALL report recommends that, for loss of material due to pitting and crevice corrosion, the effectiveness of the Water Chemistry Control Program should be verified to ensure that significant degradation is not occurring. The applicant is requested to perform a one-time inspection to verify the effectiveness of the Water Chemistry Control Program or to provide justification for not performing a one-time inspection.

Response (applies to a and b)

The FNP Water Chemistry Control Program provides for control of chemistry parameters associated with corrosion of stainless steel components in steam and power conversion systems. This program is consistent with the guidance contained in EPRI TR-102134, "Secondary Water Chemistry Guidelines." In accordance with EPRI TR-102134, chloride and sulfate concentrations are maintained in the low ppb range. Additionally, dissolved oxygen concentrations are maintained in the low ppb range through the addition of oxygen scavengers. Under these conditions, corrosion of austenitic stainless steel components is unlikely.

The FNP operating experience review performed for development of the FNP license renewal application did not identify any failures of stainless steel components in steam and power conversions systems due to cracking or loss of material. The operating experience review also confirmed the FNP Water Chemistry Control Program has effectively monitored and maintained chemistry parameters within specified target values. Minor instances of chemistry parameters outside of specified limits were promptly restored to within acceptable limits. This site specific operating experience confirms that the Water Chemistry Control Program without an inspection program is adequate to manage this aging effect without performing a one-time inspection.

Furthermore, comparison to previous applicants indicates that the FNP aging management strategy for stainless steel components exposed to a steam or treated water environment is similar to the strategy previously approved by the NRC staff. Refer to Past Precedent Review PPR-AMS-M03, "Aging Management for Stainless Steel Components Exposed to a Steam or Treated Water Environment," previously provided to the NRC.

RAI 3.4-3

LRA Table 3.4.2-1 identifies loss of material as an aging effect for alloy steel steam/fluid traps in a steam and treated water environment. The applicant credits the Water Chemistry Control Program to manage this aging effect. The GALL report recommends Water Chemistry Control and a one-time inspection to manage loss of material for carbon/alloy steel components in a treated water environment. The applicant is requested to perform a one-time inspection to verify the effectiveness of the Water Chemistry Control Program or to provide justification for not performing a one-time inspection.

Response

LRA Table 3.4.2-1 applies to components in the Main Steam System. Section VIII.B1, *Main Steam System (PWR)*, of NUREG-1801 recommends Water Chemistry to manage loss of material for carbon steel components in a steam environment. A one-time inspection is not specified. LRA Table 3.4.1 Item Number 3.4.1-7 is the NUREG-1801 (GALL) aging management evaluation summary item that applies to these Main Steam System components. FNP conservatively managed alloy steel the same as carbon steel. The GALL report summary item that recommends water chemistry control and a one-time inspection to manage loss of material for the steam and power conversion systems (LRA Table 3.4.1 Item Number 3.4.1-2) excludes the main steam system.

A one-time inspection is not necessary for Main Steam System components because the very low oxygen concentration and the ultra-high purity of the steam exiting the steam generators precludes significant corrosion of the carbon steel and alloy steel components in this system. While the steam traps will be exposed to treated water (condensed steam) as well as steam, there is not sufficient oxygen or contaminants in the condensed steam to promote significant corrosion of alloy steel components. This position is supported by FNP operating experience. This is consistent with LRA Table 3.4.1, *Summary of Aging Management Evaluations for Steam and Power Conversion Systems in Chapter VIII of NUREG-1801*, Item Number 3.4.1-7.

RAI 3.4-5

LRA Table 3.4.1-4 states that loss of material was determined not to be an aging effect requiring management for the auxiliary feedwater (AFW) system turbine oil cooling system. Table 3.4.2-4 identifies no aging effects requiring management for carbon and stainless AFW components in an oil environment. For AFW oil cooler tubes, Table 3.4.2-4 only identifies fouling as an aging effect requiring management. The GALL report recommends a plant-specific aging management program for loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC in carbon and stainless steel components exposed to lubricating oil that may be contaminated with water. The staff considers a periodic inspection program appropriate to manage these aging effects. Industry operating experience indicates that moisture in oil has caused degradation in these types of components. For the filters, flow orifice/element, oil cooler shell, oil cooler channel head, oil cooler tube sheet, oil cooler tubes, piping, pump casings, and valve bodies in the AFW system exposed to an oil environment, the applicant is requested to provide aging management for loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC, or to provide justification for not managing this aging effect.

Response

The SNC position as stated in LRA Section 3.4.2.2.5 is that lubricating oil systems at FNP are not assumed to be contaminated with water. Lubricating oil systems are assumed to be free of water contamination as their initial condition. Lubricating oil systems are typically closed systems that have little potential for ingress of contaminants unless a component failure occurs. License Renewal does not assume component failures as a means to establish the conditions necessary for aging to occur. For example, tube failures in lubricating oil coolers are not assumed because the cooling water side of the tubes is age-managed. Therefore, water contamination of lubricating oil is event driven, and would be addressed by corrective maintenance. For License Renewal purposes, lubricating oil is therefore assumed to be free of water contamination.

Although they are not credited for aging management, other site activities provide added assurance that lube oil is not contaminated with water. Oil levels are visually checked every shift for proper level and for visual evidence of contamination (milky appearance of oil or visible oil/water boundary). The oil is sampled every three months and is changed based on the results of the sample analysis. Oil levels and condition are also checked during quarterly pump surveillance testing.

The EPRI Mechanical Tools indicate that significant corrosion is only expected where water can settle or pool. However, since water contamination is not expected, lubricating oil systems are not susceptible to loss of material due to general corrosion, pitting, crevice corrosion or MIC. FNP operating experience supports this conclusion.

Furthermore, Past Precedence Review PPR-AMS-M05, "Aging Management for Stainless Steel AFW System Lubricating Oil Coolers", previously provided to NRC, concludes that the SNC aging management strategy is consistent with the strategy of prior applicants that has previously been accepted by the NRC Staff.

RAI 3.4-6

LRA Table 3.4.2-4 identifies fouling as an aging effect for the AFW oil cooler tubes in both an oil and treated water environment and the oil cooler tube sheet in a treated water environment. The applicant credits the One-Time Inspection Program to verify this aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect the component intended function during the period of extended operation. The applicant's One-Time Inspection Program scope in Section B.5.5.5 of the LRA identifies specific components included in the sample population. This sample population does not include the oil cooler tubes or tube sheet, and the items identified in the list do not appear to bound the aging effect of fouling on the oil cooler tubes or tube sheet. The applicant is requested to explain why the One-Time Inspection Program sample population does not contain inspection criteria for the tubes.

Response

The AFW system oil cooler listed in LRA Table 3.4.2-4 is the turbine driven auxiliary feedwater pump (TDAFWP) turbine lube oil cooler.

LRA Table 3.4.2-4 identifies the aging effect "fouling" for the stainless steel AFW oil cooler tubes, tube sheet, and channel head in a treated water environment. Further evaluation indicates that fouling is not a plausible aging mechanism for this material and environment combination. The cooling water for the FNP AFW oil cooler is drawn from the AFW supply to the pump. This is the same treated water which is stored in the condensate storage tank. At FNP, the rigorous chemistry controls maintained on this system eliminate fouling as a plausible aging effect. FNP operating experience supports this conclusion. Fouling will be removed as an aging effect requiring management for stainless steel AFW oil cooler components in the treated water environment. Fouling of the oil cooler tubes in a lube oil environment remains as an aging effect managed by the One-Time Inspection (OTI) Program.

The listing of components under "Specific Components Included in Sample Population" in Section B.5.5.5 identifies components with unique aging issues. These components have been listed separately to ensure these unique component issues are addressed. The AFW oil cooler tubes (lube oil environment) should have been included in this listing. However, the Staff should note that the scope descriptions in Appendix B provide a summary-level scope description for the program versus the more detailed scope defined by the aging management review results presented in the LRA Section 3 Tables. One-time inspection of the AFW oil cooler tubes for fouling is specifically identified in the Section 3 tables and in SNC's supporting documentation ("Master Document") for the OTI Program. SNC has included fouling as a parameter inspected under the OTI Program as identified in Section B.5.5.7, "Parameters Monitored and Inspected."

To address the Staff's concern, SNC will include one-time inspection of the TDAFWP turbine lube oil coolers within the listing of One-Time Inspections on the License Renewal Future Actions Commitment List.

RAI 3.4-7

LRA Table 3.4.1-11 states that the External Surfaces Monitoring Program will manage loss of material of the external surfaces of the condensate storage tanks, and that the program is consistent with the intent of NUREG-1801 Volume 2 (GALL), XI.M29, "Aboveground Carbon Steel Tanks" aging management program. The staff has the following comments regarding this item: 1) The applicant is requested to clarify the meaning of the phrase "intent of." If External Surfaces Monitoring Program is not consistent with NUREG-1801, describe any differences between the two programs; 2) For tanks supported on earthen or concrete foundations, the GALL program XI.M29, "Aboveground Carbon Steel Tanks," recommends a thickness measurement of the tank bottom surface as verification that unacceptable degradation is not occurring from the exterior. The External Surfaces Monitoring Program does not contain a thickness measurement of the tank bottom. Describe how the applicant will manage aging on the exterior bottom of the condensate storage tank; and 3) For tanks listed in LRA Table 3.4.2-5, describe if any of these carbon steel tanks have inaccessible tank bottoms and, if so, how these aging effects will be managed.

Response

1) The External Surfaces Monitoring Program is a plant-specific program and is not specifically addressed in NUREG-1801 as stated in LRA Section B.5.3. In addition, Table B.2.0 in LRA Section B.2.0, "Aging Management Program Correlation to NUREG-1801," specifically states that the GALL XI.M29 program is not credited for license renewal at FNP. Therefore, a consistency comparison of the External Surfaces Monitoring Program to the GALL program XI.M29, *Aboveground Carbon Steel Tanks*, is unnecessary. The External Surfaces Monitoring Program is to be evaluated separate from the consistent with GALL process.

   SNC acknowledges that our statement the External Surfaces Monitoring Program is "*consistent with the intent of*" GALL XI.M29 in the discussion section for Item 3.4.1-11 "External Surface of Aboveground Carbon Steel Tanks", is a source of confusion. The purpose of the statement was to indicate that both programs manage the effects of corrosion on the external surfaces of the aboveground portions of carbon steel tanks. The intent of XI.M29, *Aboveground Carbon Steel Tanks*, is to manage the effects of external corrosion on the intended function of these tanks. The External Surfaces Monitoring Program meets the intent of XI.M29 for accessible external surfaces of above ground carbon steel tanks. Inaccessible surfaces are not within the scope of the External Surfaces Monitoring Program. See our response to item 2 of this response for the inaccessible tank bottom external surface.

2) The condensate storage tanks (CST) at FNP are set on a four foot thick concrete foundation. The top of this foundation is slightly above grade in a well drained area. There is a one inch layer of sand between the concrete and the bottom of the tank. The gap between the bottom of the tank and the concrete at the periphery of the tank is sealed with grout. A path for water intrusion would require noticeable damage to the grout, which is inspected by the Structural Monitoring Program.

In order to verify the position that the CST bottoms are not experiencing aging on the exterior surface, the One-Time Inspection Program will be revised to include a thickness measurement of the bottom of the Unit 1 CST prior to the period of extended operation.

3) The Component Type "Tanks" in LRA Table 3.4.2-5 refers to the Auxiliary Steam Condensate Tanks and Condensate Return Unit Tanks. These tanks are located inside the Auxiliary Building for each unit. The exterior surfaces of the bottoms of these tanks are accessible for visual inspection.

RAI 3.5-1

In discussing Item Number 3.5.1-3 (Table 3.5.1) of the LRA, the applicant asserts that the FNP AMR results are consistent with NUREG-1801. NUREG-1801 under item A3.1 (page II A3.6) recommends further evaluation regarding the stress corrosion cracking of containment bellows. The applicant is requested to provide additional information regarding the containment pressure boundary bellows at FNP, relevant operating experience, and method(s) used to detect their age related degradation. In many cases, VT-3 examination of IWE, and Type B, Appendix J testing cannot detect such aging effects (See NRC Info Notice 92-20).

Response

The evaluation results for stress corrosion cracking of containment penetration sleeves and bellows are associated with Item Number 3.5.1-2 in LRA Table 3.5.1 which states the aging effect/mechanism is not applicable to FNP and refers to Section 3.5.2.2.7 for further discussion. At FNP, stress corrosion cracking is not an applicable aging mechanism for containment bellows based on the material and environment combination and operating experience.

FNP performed an evaluation of NRC IN 92-20, "Inadequate Local Leak Rate Testing." This IN discusses inadequate Type B local leak rate testing for two-ply stainless steel bellows. The single-ply steel bellows assembly used at FNP is not similar in design or construction to the bellows described in the IN. The FNP bellows is tested in accordance with 10CFR50 Appendix J.

The only location that penetration bellows are used at FNP is in the fuel transfer tube assembly. A description of the fuel transfer tube including the bellows assembly, relevant operating experience, and testing is given below.

Fuel Transfer Tube

The fuel transfer tube penetrates the containment wall connecting the refueling canal in containment with the fuel transfer canal in the Auxiliary Building. This penetration consists of a pipe installed inside a sleeve. The tube is sealed to the steel liners in both the refueling canal and fuel transfer canal. The tube is closed with a blind flange on the containment side and a gate valve on the Auxiliary Building side. Expansion joint bellows (single-ply) provide for relative movement between containment and the Auxiliary Building structures.

Portions of the fuel transfer tube are exposed to a wetted environment during certain operating modes. The portions of the fuel transfer tube exposed to this wetted environment are constructed from stainless steel. Rigorous chemistry controls limit the concentration of aggressive chemical species so this environment is not corrosive to stainless steel. In addition, the operating temperature of the water in the refueling canal and the fuel transfer canal is sufficiently low so that the bellows remain below the threshold temperature for stress corrosion cracking (i.e., <140°F). During other operating modes the fuel transfer tube is exposed to an "Inside" environment at ambient temperature. The Inside environment is not corrosive to stainless steel. Stainless steel bellows are very compliant (flexible), therefore sustained high tensile stress does not

exist. Since a corrosive environment and a high level of sustained tensile stress do not exist for the fuel transfer tube bellows, SCC on penetration bellows is not considered an aging effect requiring management.

FNP plant-specific operating experience has not identified cracking of these bellows as an aging effect requiring management.

Routine penetration sleeve leak rate testing (Type B) is performed from outside the containment via test connections that are installed in the sleeve end plates, such that the entire sleeve, including bellows, is tested as one unit.

RAI 3.5-2

For seals and gaskets related to containment penetrations, in Item Number 3.5.1-6 of the LRA, containment ISI and containment leak rate testing have been stated as the aging management programs. For equipment hatches and air-locks at FNP, the staff agrees with the applicant's assertion that the leak rate testing program will monitor aging degradation of seals and gaskets, as they are leak rate tested after each opening. For other penetrations with seals and gaskets, the applicant is requested to provide information regarding the adequacy of Type B leak rate testing frequency to monitor aging degradation of seals and gaskets at FNP.

Response

The containment penetrations with seals and gaskets addressed in item Number 3.5.1-6 in addition to the equipment hatches and air-locks are in the following two categories: (1) electrical penetrations, and (2) mechanical penetrations with blind flange closure assemblies. These penetrations (ASME Section XI Subsection IWE examination category E-P) are subjected to Type B local leak rate testing. Farley Nuclear Plant implements Option B "Performance-Based Requirements," for establishing testing intervals for Appendix J (and IWE category E-P).

The criteria for extending the testing interval for Type B testing are based on NEI 94-01 (Nuclear Energy Institute Industry Guideline For Implementing Performance-Based Option of 10 CFR Part 50, Appendix J). This allows the testing interval to be extended to 60 months on the successful completion of two Type B tests. On the successful completion of three Type B tests the testing interval may be extended to 120 months.

Specific discussion of the testing frequencies for each of these categories of penetrations with seals and/or gaskets follows.

Electrical Penetrations

The electrical penetrations have been divided into three groups for testing purposes. These are 4160V, 600V and instrumentation/control penetrations. Approximately 1/3 of the electrical penetrations will be tested in each 40 month period, with some from each group selected. A representative sample is looked at over a short duration and will identify any generic aging issue applicable to the other electrical penetrations.

Mechanical Penetrations

The mechanical penetrations with blind flange closure assemblies addressed in Item Number 3.5.1-6 of the LRA are:

- Fuel Transfer Tube;
- Spare Penetrations 90 and 92 used to run temporary cables inside containment during outages (e.g., steam generator examinations);
- Containment Integrated Leak Rate Testing (ILRT) Penetrations 71 and 72 which have been modified to allow routing of temporary cables and hoses inside containment (e.g., steam generator activities).

These penetrations are typically opened every refueling outage. An as-left test is performed after closure following an outage. As-found testing has been determined to be unnecessary on these penetrations. These penetrations are not manipulated during the operating cycle and do not experience the degradation associated with penetrations which are in service. The LLRT history of these penetrations shows that As-found testing has been satisfactory with no unexpected leakages and that they qualify for an extended interval test schedule. The As-found leakage rates correspond closely with the previous As-left leakage rates. By not performing the As-found testing, a considerable dose savings is realized, especially in the case of the fuel transfer tube blind flange. Savings in manpower also result from not performing this testing.

If an As-left Type A test is to be performed during a refueling, an As-found and As-left Type B test may be required. This is to allow an As-found Type A leakage rate to be calculated based on any improvements in the LLRT leakage rates made during the outage. The As-found testing will be performed on the required extended inspection interval frequency.

RAI 3.5-4

In discussion of Item 3.5.12 in Section 3.5.2.2.4, the applicant notes that the moisture barrier is monitored under IWE for aging degradation. The industry experience indicates that the moisture barrier degrades with time, and any moisture accumulation in the degraded barrier corrodes the steel liner. The applicant is requested to provide information regarding the operating experience related to the degradation of moisture barrier and the containment liner plate at FNP. Please include a discussion of acceptable liner plate corrosion before it is reinstated to the nominal thickness.

Response

Operating Experience

The following is a discussion of the operating experience related to the degradation of moisture barrier and the containment liner plate at FNP.

Moisture Barrier

Visual examinations of the moisture barrier have been performed in each unit for wear, damage, erosion, tear, surface cracks, and other defects which may violate the leak-tight integrity. The Moisture Barrier is located along the periphery at the mating surface between the containment liner and concrete fill at elevation 105'-6". The condition of the moisture barrier in each unit is very good with hardly any sign of cracking or flaking. Since no significant degradation of the containment liner plate and moisture barrier at the interface between the concrete fill and the containment liner plate has occurred, no boroscopic examination has been performed.

Liner Plate

The liner has been visually examined in each unit. In general, the liner in each unit is in good shape. Some paint blisters, flaking and stain marks were noted, however examination of some of the blisters reveals that the primer coating is still intact and only the top coating has flaked out. An evaluation determined that the liner paint blisters were caused by the epoxy topcoat stress relieving itself during the initial pressurization tests and containment heatups.

The liner plate is bowed out at a few places leaving a void between the concrete surface and the liner plate. There is no sign of any crack or paint peeling at these locations. It was determined that thickness of the plate at the location was more than or equal to the design thickness of 1/4". The size of the bowing varied but it was in the order of 1'-2 1/2" X 4'-0" approximately and occurred between the insert points. It was determined that this condition existed from construction time and did not happen due to any corrosion behind the liner. There is no evidence of degradation that might affect either the containment structural integrity or leak tightness.

Some punch marks of approximate size 1/16" diameter X 1/32" deep have been identified on the liner plate. The purpose/source of these markings could not be determined. Since the depth of penetration was less than 10% of the design

thickness the condition was considered acceptable per ASME Section XI Subsection IWE, Paragraph IWE-3122.4.

In Unit 1, during steam generator replacement (U1R16) a nozzle cover for the old steam generator was dropped accidentally from elevation 155' to elevation 105'. Damage marks on the containment liner were noticed at five locations and closely examined. The coating came out at all five locations exposing the liner plate surface with no sign of cracking at any location. At one location, a dent on the plate was noticed and the depth of the dent was measured to be on the order of 1/48". It was concluded the damage was insignificant in nature, did not pose any evidence of degradation that might affect either the containment structural integrity or leak tightness, and was acceptable as-is with no repair recommended.

Liner Plate Corrosion Acceptance Standard

FNP's acceptance standard is based on IWE-3000. As per IWE-3122.4, components whose examination results reveal flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-3410-1 shall be acceptable for service without the removal or repair of the flaw or area of degradation or replacement if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. When supplemental examination of IWE-3200 is required, if either the thickness of the base metal is reduced by no more than 10% of the nominal plate thickness or the reduced thickness can be shown by analysis to satisfy the requirements of the Design Specifications, the component shall be acceptable by evaluation (however corrective action to restore the base metal to the nominal plate thickness may be performed).

Containment examinations are predominantly visual. If evidence of degradation (e.g. pitting, blistering, checking, cracking, flaking, etc.) is detected during the general visual examination, a detailed examination is performed to determine if corrosion is occurring and the extent of corrosion. An engineering evaluation determines if the corrosion requires correction to the nominal thickness by repair or replacement, and will consider the actual plate thickness versus minimum required, aggressiveness of the corrosion, and follow-up inspection frequency.

RAI 3.5-5

With reference to LRA Item 3.5.1-15, the following information is requested:

> In 1985, the incident of post-tensioning anchor-head failures had occurred at FNP, Unit 2. The event is partially documented in NRC Information Notices 85-10 and its Supplement 1. Please provide a description of the subsequent actions taken, together with the operating experience as to the effectiveness of the corrective actions taken. Also, indicate, if any other actions are (and will be) continued in addition to the IWL tendon inspections to ensure the integrity of the tendon anchor-heads.

Response

An inspection of containment prior to the Integrated Leakage Rate Test (ILRT) for FNP Unit 2 during the 3rd refueling outage discovered that the cover for the shop end of containment vertical tendon V17 was deformed. Further examination determined that the anchor had broken allowing the tendon to detension completely. On further inspection, two additional failures were discovered in Unit 2 and none in Unit 1.

A tendon inspection and repair effort was initiated to locate failures, determine the cause of the failures, and perform repairs and corrective maintenance.

Visual inspections for moisture on the field anchorage components and for evidence of failed field anchors was performed on all Unit 1 and 2 vertical and eight Unit 2 horizontal field anchors. The tendon field anchors were removed, magnetic particle tested and replaced with new or acceptable used anchors. Repairs consisted of field anchor replacement, magnetic particle testing of removed anchors, and greasing. Laboratory investigations concluded that the most likely cause of failure was hydrogen induced stress cracking.

All vertical field anchors were regreased using a new grease treatment procedure to ensure grease coating on the front and back surfaces of the anchor prior to retensioning.

Visual inspection for moisture and cracks was performed on a random sample of dome and horizontal tendons sufficient to establish a 95% probability with a 95% confidence level that no other failed anchors exist. Since at one time it was thought that ground water may be the source of tendon moisture, all horizontal tendon field anchors below ground level were also inspected for moisture. No failed field anchors were found in these two groups.

In order to ensure the continued structural integrity of the containment tendon field anchors in both units, the following follow-up inspections and tests were performed:

- Following one year of service after completion of the tendon inspection and repair effort, all vertical tendon field anchors in each unit were visually inspected for evidence of moisture.

- Following three years of service after completion of the tendon inspection and repair effort, horizontal and dome tendon field anchors were visually inspected for evidence of moisture and evidence of failure on a random sample basis to establish a 95% probability with a 95% confidence level that no failed field anchors exist in either group.

In addition to the actions described, the tendon surveillances required by the Technical Specifications were performed. Tendon surveillances since the incident do not suggest any abnormal degradation of the tendon system and the results demonstrate that containment structural integrity has been maintained continuously for both units. No additional actions beyond the IWL tendon inspections are planned during the period of extended operation to ensure the integrity of the tendon anchor-heads.

RAI 3.5-7

With respect to the AMR result provided in Table 3.5.2-2 of the LRA (page 3.5-40) for compressible joints and seals, discuss past FNP's operating/inspection experience pertaining to change in material properties and cracking of elastomers to justify that the inspection frequency adopted in the Structural Monitoring Program is adequate to ensure proper functioning of the FNP's compressible joints and seals.

Response:

Periodic inspection frequencies have been selected to provide assurance that any age-related degradation is detected at an early time so that appropriate corrective actions can be implemented. Initially, this period was set at five years so that the overall condition of each in-scope structure or structural component is inspected every five years. Subsequent inspections have verified that the compressible joints and seals are performing as required and degradation has been detected prior to loss of function with the five year inspection frequency. The Structural Monitoring Program includes provisions to adjust the frequency of inspection based on the inspection results.

The compressible joints and seals constructed of elastomer materials have performed very well at FNP. There have been minor instances of water seepage past elastomer compressible joints and seals requiring remedial action. Seepage occurred at a location on the bottom elevation of the Auxiliary Building and in the Electrical Cable Tunnels at the interface with the Auxiliary Building (near the location of the watertight doors) which is protected by a water stop. This seepage was not the result of age-related degradation but rather was a function of the local hydraulic conditions. These conditions were identified through normal plant activities including the Structural Monitoring Program and remedial action was taken (use of hydrophilic grout). The Structural Monitoring Program continues to periodically inspect these areas as part of the spaces-based inspections.

In addition to the elastomer material listed in Table 3.5.2-2, some compressible joints and seals in the Auxiliary Building are constructed of a cork material. This cork material was inadvertently omitted from the table. The cork material was used during initial forming of the concrete to fill the seismic gaps between the floor slabs and vertical walls of the Auxiliary Building and the Containment wall. The cork ensured the required gap was maintained during the forming process and acts as seal between adjoining spaces and elevations. In certain locations, these seals prevent flooding interaction between spaces.

There have been isolated cases of the cork joint fillers slipping out of the gap (since the original joint design does not provide any substantial retention mechanism (other than friction between the surfaces). The cork material appears to be in good condition, however shrinkage and differential movement between the two mating surfaces is believed to have resulted in the slippage. Where necessary, the cork was replaced, and in some cases elastomer sealant compounds were used. The Structural Monitoring Program inspection frequency is adequate to detect the degradation (slippage) of the cork material prior to loss of any intended function.

As indicated above, the "Compressible Joints and Seals" line item in Table 2.4.2.1, "Auxiliary Building Component Types Subject to Aging Management Review and their Intended Functions," should have included "Flood Barrier" as an intended function. The

"Compressible Joints and Seals" line item should have read as follows (additions are indicated in ***Bold Italics***):

Component Type	Intended Function
Compressible Joints and Seals	Shelter / Protection ***Flood Barrier***

The Auxiliary Building aging management review summary for the compressible joints and seals line item in Table 3.5.2-2 of the LRA (page 3.5-40) should have read as follows (additions are indicated in ***Bold Italics***):

Component Type *GALL Reference*	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Compressible Joints and Seals	Shelter / Protection ***Flood Barrier***	Elastomers	Inside and Outside	Change in Material Properties and Cracking	Structural Monitoring Program			J
		Cork	***Inside*** ***and*** ***Outside***	***Change in Material Properties***	***Structural Monitoring Program***			***J***

RAI 3.5-8

For the following two items, the applicant is requested to discuss the key characteristics of FNP's outside environment, its past operating/inspection experience with respect to aging management of the components listed, and justify its position that no AMP is needed for the components.

a. Regarding the stainless steel penetration sleeves listed on Table 3.5.2-2 (page 3.5-43) of the LRA that are exposed to outside environment, no AMP is credited to manage aging of these components. Depending on the plant site specific parameters that define the 'outside environment,' some stainless steel components exposed to sustained, aggressive outside environment might still be subjected to appreciable loss of material aging effect.

b. Table 3.5.2-9, (page 3.5-64) of the LRA indicates that FNP cable trays, conduits, ducts, and tube tracks that are made of aluminum and stainless steel and exposed to inside and outside environment have no applicable aging effect requiring management and, therefore, no AMP is credited to manage their aging. Sustained exposure to a chemically aggressive or acidic outside environment might result in aging of these components.

Response (applies to a and b):

Past inspections of stainless steel penetrations and aluminum and stainless steel cable trays, conduits, ducts, and tube tracks in an outside environment have identified only minor surface oxidation and discoloration. Past inspections do not indicate any appreciable loss of material aging effect. Corrosion of stainless steel and aluminum components has typically been associated with marine / industrial environments where the presence of significant amounts of contaminants results in localized corrosion or stress corrosion. FNP is located in a rural environment away from the coastline and with few sources of industrial pollutants. These components are not insulated, eliminating the potential for the insulation to retain moisture and leach halides onto the surfaces. Rain has been found to wash contaminants off of un-insulated components, instead of concentrating them. Therefore, these components are not considered to be exposed to a chemically aggressive or acidic environment. FNP operating experience confirms this position.

RAI 3.5-9

Table 3.5.2-3 (page 3.5-45) of the LRA indicates that the compressible joints and seals consisting of fiber, foams and ceramics used in FNP Diesel Generator Building that are exposed to below grade environment have no applicable aging effect requiring management and, therefore, no AMP is credited to manage aging of the same. Since sustained exposure to an aggressive below grade environment might result in aging of these components, FNP is requested to discuss key characteristics of its below grade environment as well as its past operating/inspection experience with respect to aging management of these components and justify its position that no AMP is needed for the listed components.

Response

The below grade environment at FNP is not aggressive. Soil used in the vicinity of the Diesel Generator Building and other seismic Category I structures is controlled and compacted backfill. The ground water is considered non-aggressive because the chlorides, sulfates and pH are well in the ranges identified as non-aggressive by the EPRI Structural Tools (TR-1002950, Aging Effects for Structures and Structural Components (Structural Tools), Revision 1). Recent water samples from the service water pond and an on-site construction well have yielded a pH ranging from 6.7 to 7.1 (greater than the aggressive pH < 5.5), chloride solutions ranging from 3.7 ppm to 2.0 ppm (less than the aggressive Cl > 500 ppm), and sulfate solutions ranging from 5.3 ppm to 6.4 ppm (less than the aggressive SO_4 > 1500 ppm).

There is no history of aging degradation or failure of compressible joints and seals consisting of fiber, foams and ceramics exposed to a below grade environment.

RAI B.5.3-1

The GALL report recommends that acceptance criteria for inspections be in accordance with the ASME Code. The applicant is requested to explain if inspection criteria for the external surfaces monitoring program will be in accordance with the ASME code. In cases where the ASME code is not applicable, explain what criteria will be used to determine acceptability during these inspections.

Response

The FNP External Surfaces Monitoring Program is a plant specific program. Comparisons to program attributes contained within NUREG-1801 generic aging management programs are not necessary. Therefore, acceptance criteria for component inspections conducted under the FNP External Surfaces Monitoring Program may not be based upon ASME Code requirements.

FNP plant procedures implementing the External Surfaces Monitoring Program will contain guidance regarding parameters to be inspected and criteria for evaluating component degradation. This approach is a condition monitoring program similar to the Structural Monitoring Program. NUREG-1801, Section XI.S6, *Structures Monitoring Program*, says in part, "Acceptance criteria are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience" and "The plant-specific structures monitoring program is to contain sufficient detail on acceptance criteria to conclude that this program attribute is satisfied." The External Surfaces Monitoring Program will employ a similar approach.

The External Surfaces Monitoring Program is focused on monitoring external surfaces of mechanical systems and initiating corrective action prior to conditions becoming problematic. Where practical, acceptance criteria for the External Surfaces Monitoring Program will be specifically tailored to the component type, materials of construction, and expected aging effects. Inspection criteria may include, for example, flaking or peeling of paint (if the surface is painted), rust scale, rust stains, cracking (elastomers), or visible leakage.

Evaluation criteria for categorizing the overall component condition will also be included (similar to the Structural Monitoring Program's use of "acceptable", "acceptable with deficiencies" and "unacceptable"). The acceptance criteria will ensure an inspected component does not exhibit any visible indications that could result in a failure of the component to perform its intended function prior to the next inspection, and will identify if corrective action is needed. The evaluation criteria will consider not only the current severity of the degradation, but the expected environmental aggressiveness of the area surrounding the component.

Inspection results that are not acceptable will be entered into the Corrective Action Program in accordance with FNP procedures. The Corrective Action Program evaluates the degraded condition including compliance with applicable design basis codes such as the ASME Code as appropriate. Corrective actions are tailored to the situation and can range from restoration/refurbishment to replacement.

RAI 4.3.4-1a

10CFR54.21(c)(1)(ii) requires that the applicant demonstrate the adequacy of the analysis projected for the extended period of operation. In order for the staff to make a reasonable assurance conclusion, the applicant is requested to provide the following information:

(a) Minimum required prestressing forces for each group of tendons,

Response

The following are the minimum required prestressing forces. This information was originally used in the FNP Technical Specifications (Figure 4.6-1) prior to conversion to the Improved Standard Technical Specifications format.

Hoop Tendon = 6.01 kip /wire
Dome Tendon = 6.35 kip/wire
Vertical Tendon = 6.81 kip/wire

RAI 4.3.4-1b

10CFR54.21(c)(1)(ii) requires that the applicant demonstrate the adequacy of the analysis projected for the extended period of operation. In order for the staff to make a reasonable assurance conclusion, the applicant is requested to provide the following information:

(b) Trend lines of the projected prestressing forces for each group of tendons based on the regression analysis of the measured prestressing forces (see NRC Information Notice 99-10 for more information).

Response

The Nuclear Regulatory Commission (NRC) issued Information Notice (IN) 99-10 to alert addressees of degradation to prestressing system components of prestressed concrete containments.

One of the specific areas addressed by the IN is the trend analysis of prestressing forces. The IN states the appropriate method for evaluating the adequacy of the tendon force is to use linear regression analysis using individual lift-off forces, instead of the averages of the lift-off forces. FNP has performed a linear regression analysis using a number of individual lift-off forces of tendon force data. Past surveillances do not indicate any trend for tendon forces to fall below the minimum required prestress. To indicate the trend is within the required prestress limits, a graph of the trend using regression methods was prepared. The trend indicated by these graphs and previous evaluations shows that FNP tendons are performing as expected.

The trend lines of the projected prestressing forces for each group of tendons are shown in the response to RAI 4.3.4-1 (c).

RAI 4.3.4-1c

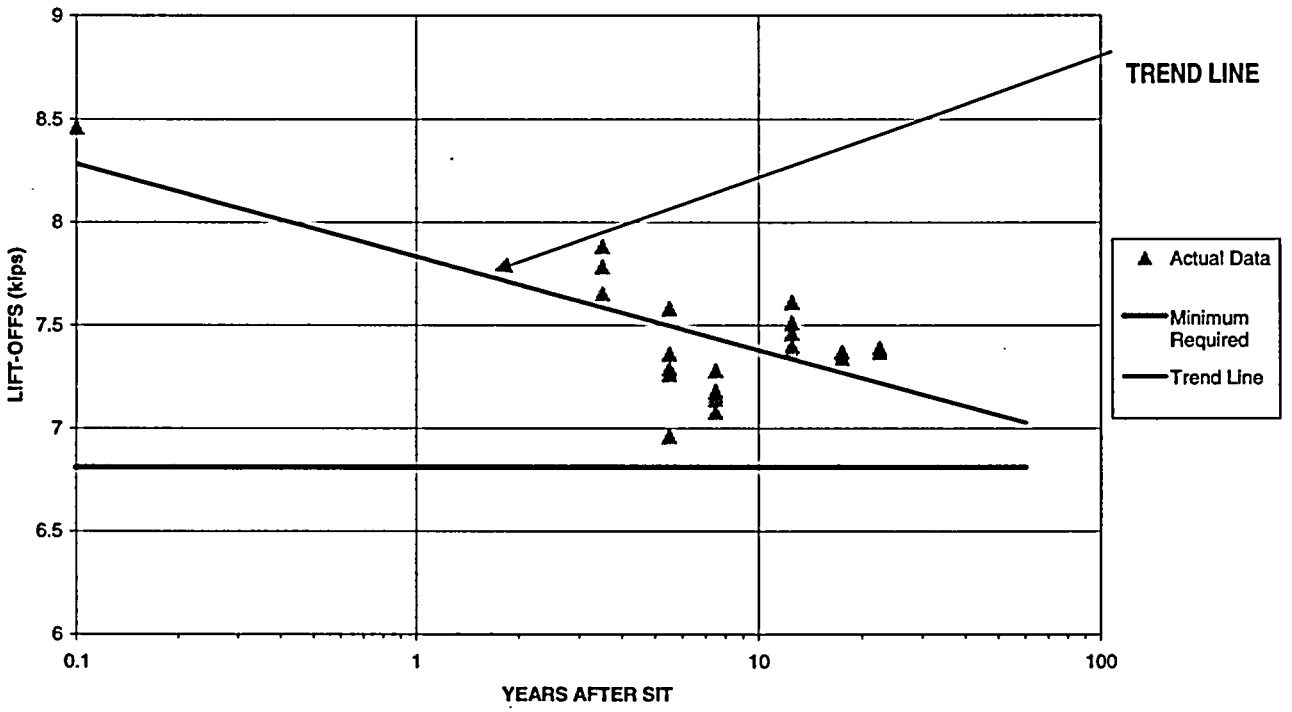
10CFR54.21(c)(1)(ii) requires that the applicant demonstrate the adequacy of the analysis projected for the extended period of operation. In order for the staff to make a reasonable assurance conclusion, the applicant is requested to provide the following information:

(c) Plots showing comparisons of prestressing forces projected to the end of the extended period of operation with the minimum required prestress for each group of tendons.

Response

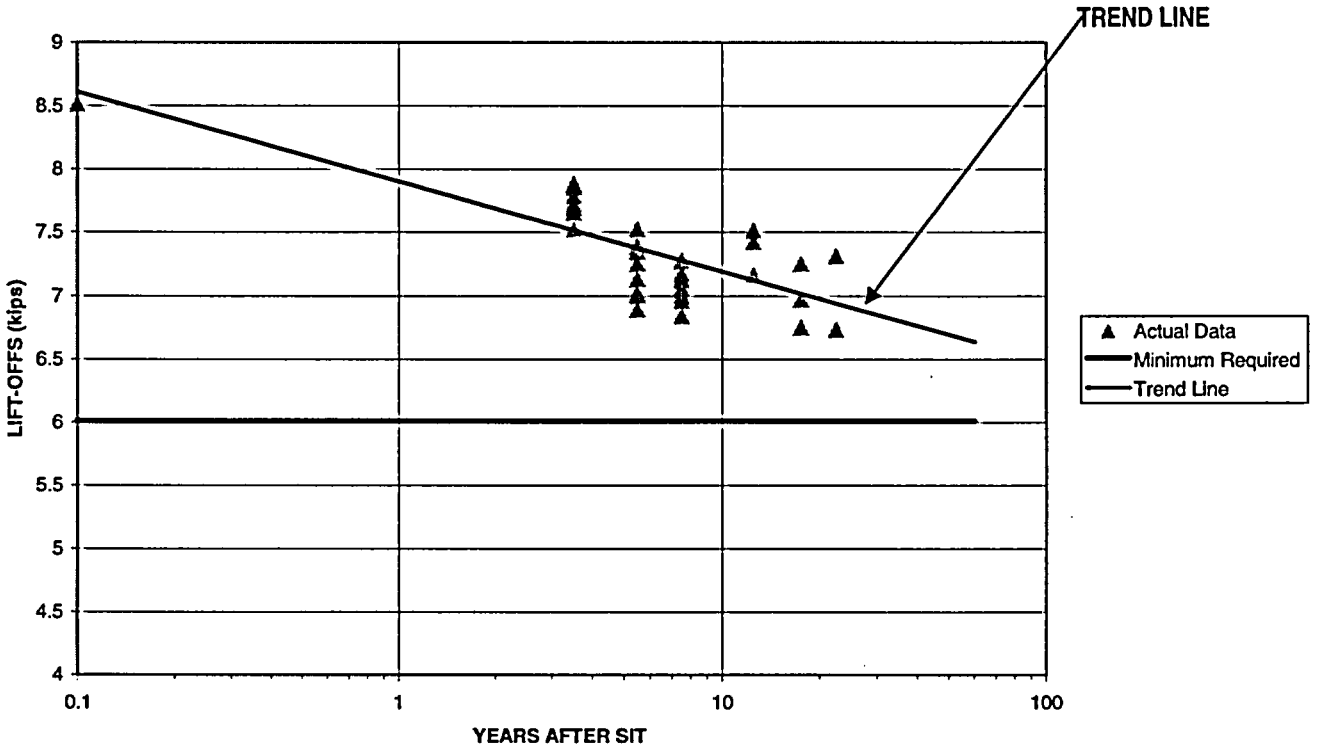
(See next page)

UNIT 1 VERTICAL TENDONS
ACTUAL FORCE TREND
(from past 6 surveillances)

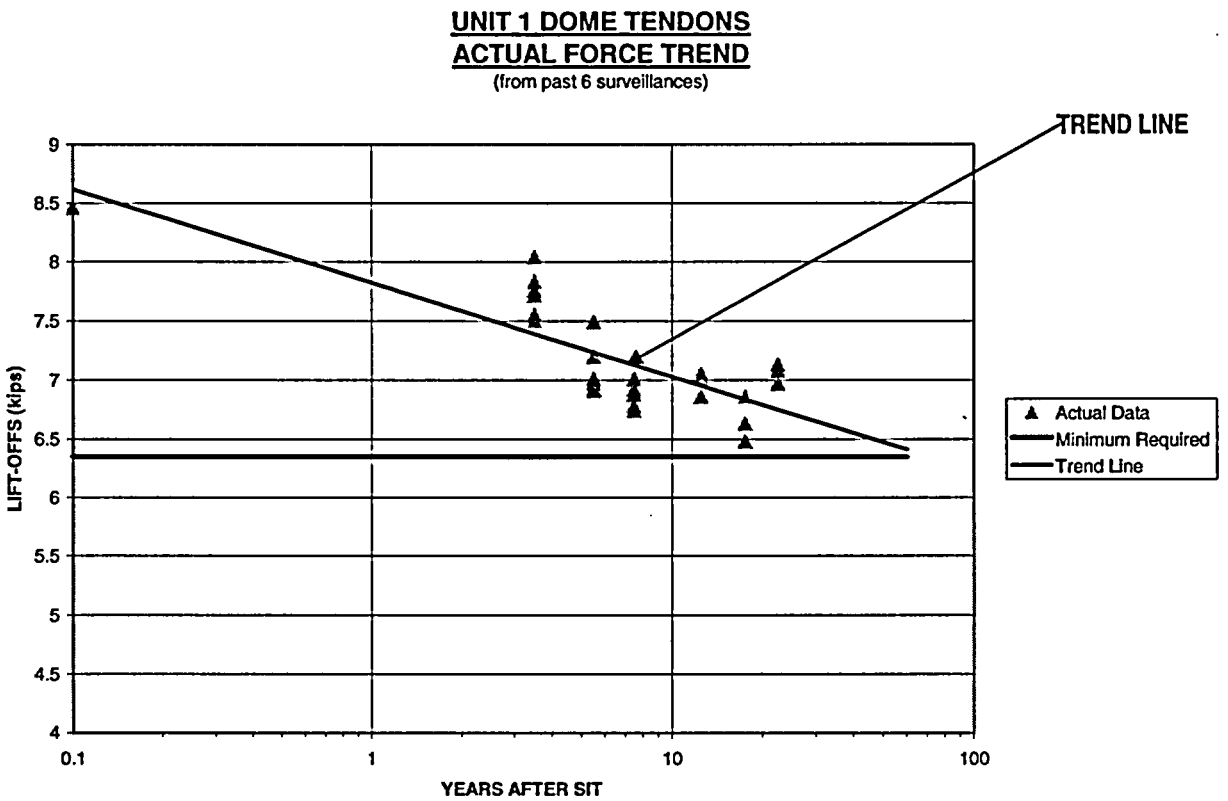


Year	Actual		Year	Actual
0.1	8.46		7.5	7.18
3.5	7.88		7.5	7.28
3.5	7.65		12.5	7.38
3.5	7.78		12.5	7.46
3.5	7.65		12.5	7.61
3.5	7.78		12.5	7.51
5.5	7.36		12.5	7.40
5.5	7.58		17.5	7.34
5.5	7.26		17.5	7.34
5.5	7.29		17.5	7.37
5.5	6.96		22.5	7.39
7.5	7.16		22.5	7.37
7.5	7.14		22.5	7.37
7.5	7.08			

UNIT 1 HOOP TENDONS
ACTUAL FORCE TREND
(from past 6 surveillances)



Year	Actual		Year	Actual
0.1	8.51		7.5	7.28
3.5	7.78		7.5	7.00
3.5	7.87		7.5	6.96
3.5	7.85		7.5	6.84
3.5	7.52		7.5	7.17
3.5	7.88		7.5	7.13
3.5	7.78		7.5	7.12
3.5	7.72		7.5	7.06
3.5	7.69		7.5	7.05
3.5	7.72		7.5	7.27
3.5	7.65		12.5	7.42
5.5	7.52		12.5	7.16
5.5	7.38		12.5	7.51
5.5	7.13		17.5	6.75
5.5	7.02		17.5	6.97
5.5	7.00		17.5	7.25
5.5	7.34		22.5	7.31
5.5	7.39		22.5	6.73
5.5	7.25		22.5	7.31
5.5	6.89			
5.5	7.35			



Year	Actual		Year	Actual
0.1	8.46		7.5	6.78
3.5	7.50		7.5	7.01
3.5	7.55		7.5	6.74
3.5	7.72		7.5	6.88
3.5	7.76		7.5	6.92
3.5	7.83		7.5	7.01
3.5	8.04		12.5	7.05
5.5	7.20		12.5	7.02
5.5	6.92		12.5	6.86
5.5	6.91		17.5	6.86
5.5	7.01		17.5	6.48
5.5	7.49		17.5	6.63
5.5	6.97		22.5	7.13
			22.5	6.97
			22.5	7.08

RAI 4.3.4-2

In Section A.4.3 in the UFSAR Supplement of the LRA, the applicant states, "The calculation indicates that acceptable containment prestress will continue to exist throughout the extended period of operation." In order for the summary to be meaningful, as a minimum, the applicant should provide a table showing the minimum required prestressing forces and the projected (to 60 years) prestressing forces for each group of tendons which would demonstrate the validity of the analysis results. The applicant is requested to supplement this information in Section A.4.3 of the UFSAR Supplement.

Response

Tabulated below are the minimum required prestressing forces and the projected (40 and 60 year) prestressing forces for each group of tendons. This supplemental information is provided at the Staff's request to demonstrate the validity of the analysis results.

The minimum required values will be supplemented in Section A.4.3 of the LRA (Appendix A Final Safety Analysis Report Supplement).

Containment Tendon Projected and Minimum Required Prestressing Forces

Tendon Type	Trend Line Values for Unit 1 [1] (kip/wire)		Minimum Required Value [2] (kip/wire)
	40 Years	60 Years	
Vertical	7.15	7.05	6.81
Hoop	6.80	6.65	6.01
Dome	6.60	6.40	6.35

(1) Values are based on interpolation from Trend Line Curve
(2) This information was originally used in the FNP Technical Specifications (Figure 4.6-1) prior to conversion to new Technical Specifications.

The minimum required values will be supplemented in Section A.4.3 of the LRA (Appendix A Final Safety Analysis Report Supplement). Section A.4.3 will be revised as follows (changes are indicated in ***bold italics***):

A.1.1 CONTAINMENT TENDON PRE-STRESS ANALYSIS

To meet the requirements on 10 CFR 50.55a(b)(2)(ix)(B), SNC used an analysis to predict the amount of residual pre-stress in the containment tendons for FNP. This analysis meets the definition of a TLAA. SNC performed a new analysis to estimate the amount of residual pre-stress on the tendons after 60 years of operation (demonstration in accordance with 10 CFR 54.21(c) (1) (ii)).

The new calculation includes the latest measurements of containment tendon pre-stress taken since the plant began commercial operation. The calculation indicates

that acceptable containment tendon pre-stress will continue to exist throughout the extended period of operation. ***The minimum required prestressing forces for the vertical, hoop, and dome tendons (kip/wire) are 6.81, 6.01, and 6.35, respectively.***