FPL

Florida Power & Light Company, 6501 South Ocean Drive, Jensen Beach, FL 34957

September 26, 2002

L-2002-166
10 CFR 54

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Re: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Response to NRC Request for Additional Information for Review of the
St. Lucie Units 1 and 2 License Renewal Application

By letters dated July 1, 2002, July 18, 2002, and July 29, 2002, the NRC requested additional information regarding the St. Lucie Units 1 and 2 License Renewal Application (LRA) Sections 2.0, 3.0, 4.0 and Appendix B. Attachment 1 to this letter contains FPL's response to the requests for additional information (RAIs) associated with the Aging Management Programs, Appendix B of the LRA.

Should you have any further questions, please contact S. T. Hale at (772) 467-7430.

Very truly yours,

D. E. Jernigan
Vice President
St. Lucie Plant

DEJ/STH/hlo
Attachment (1)

A089

St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389

Response to NRC Request for Additional Information Regarding the License Renewal Application, Appendix B - Aging Management Programs.

STATE OF FLORIDA)
) ss
COUNTY OF ST. LUCIE)

D. E. Jernigan being first duly sworn, deposes and says:

That he is Vice President - St. Lucie of Florida Power and Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information and belief, and that he is authorized to execute the document on behalf of said Licensee.

D. E. Jernigan

Subscribed and sworn to before me this

26 day of Sept., 2002.

Leslie J. Whitwell

Name of Notary Public (Type or Print)

D. E. Jernigan is personally known to me.

Leslie J. Whitwell
MY COMMISSION # DD020212 EXPIRES
May 12, 2005
BONDED THRU TROY FAIN INSURANCE, INC.

cc: U.S. Nuclear Regulatory Commission, Washington, D.C.

Chief, License Renewal and Standardization Branch
Project Manager – St. Lucie License Renewal
Project Manager - St. Lucie

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ST. LUCIE UNITS 1 AND 2
DOCKET NOS. 50-335 AND 50-389
ATTACHMENT 1
RESPONSE TO NRC REQUESTS FOR ADDITIONAL INFORMATION FOR REVIEW OF THE ST. LUCIE UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

B.3.1 NEW AGING MANAGEMENT PROGRAMS

B3.1.2 Galvanic Corrosion Susceptibility Inspection AMP

RAI B.3.1.2 - 1

In Section 3.1.2, "Galvanic Corrosion Susceptibility Inspection Program," of Appendix B to the LRA, the applicant states that inspections will be conducted on a sampling basis. Locations selected for inspection will represent those with the greatest susceptibility to galvanic corrosion. However, there are insufficient details in the LRA concerning the program for the NRC staff to determine with reasonable assurance that the program is acceptable. Provide additional information concerning the existing program or the planned development of the program elements in the following areas:

- Explain how the greatest susceptibility locations will be determined including whether these locations will be selected for each system or for all the systems.
- Explain what documents or information will be used to define the inspection interval, sample size, inspection criteria, and corrective actions.
- Explain how information concerning the inspections of the susceptible locations, the results of the inspections, and corrective actions will be managed, tracked, and evaluated.

FPL Response

Significant galvanic corrosion has not been experienced and is not anticipated in treated water systems due to the high purity of the water and its low conductivity. The Galvanic Corrosion Susceptibility Inspection Program (LRA Appendix B Subsection 3.1.2 page B-11) was developed to quantify the significance of loss of material due to this corrosion mechanism and provide for managing the effects of aging, if required. This program constitutes a one-time inspection of selected locations in treated water (and other) systems.

First Bullet

Since the inspection of all locations with the potential for galvanic corrosion is not practical, an engineering specification will be developed to provide the methodology for identifying those galvanic couples where corrosion is most likely to occur and where inspection results can be used to bound less susceptible locations. This engineering specification will also provide methods for conducting inspections, evaluation of inspection data and documentation of results. Selection of locations with greatest susceptibility to galvanic corrosion is based upon the following:

(1) How far apart the two dissimilar metals are on the galvanic series chart. The further apart, the higher the corrosion rate. Note that all stainless steels addressed by the Galvanic Corrosion Susceptibility Inspection Program are considered "passive" as

described in ASTM Standard G 82-98, "Development and Use of a Galvanic Series for predicting Galvanic Corrosion performance". As previously discussed, this program addresses the potential for galvanic corrosion in treated (high purity) water systems. Stainless steels in this environment will develop and maintain a passive protective oxide coating.

(2) The conductivity of the electrolyte. The more conductive the electrolyte, the higher the corrosion rate.

(3) The relative size of the anode and cathode. A smaller anode surface area will result in a larger corrosion rate.

The overall susceptibility of each galvanic couple in each system is assessed and ranked based upon consideration of each of the above factors. Those with greatest susceptibility are then recommended for inspection. Those that are not selected for inspection are verified to be bounded based upon electrical potential of dissimilar materials, purity of water (i.e., conductivity), and relative size of anode and cathode. For those cases where the combination of two influencing factors do not provide a conclusive ranking, the particular galvanic cell is selected for inspection. The selection process will ensure that a variety of environments are addressed by inspection including treated water - other, borated water, raw water - city water (fire protection), and air/ gas - wetted air (condensation). Where possible, inspection of galvanic couples will be included as part of plant maintenance activities.

Second Bullet

The results of the initial inspections will be assessed to determine the need for follow-up inspections. Although not anticipated, for any case where loss of material is identified, the scope and frequency of follow-up inspections will be based upon the measured wall thickness, calculated corrosion rate, projected wall thickness, and will ensure the minimum required wall thickness is maintained pursuant to the applicable code requirements. (See FPL responses to RAIs B.3.1.3-1 and B.3.1.3-2.)

Third Bullet

The results of the one-time inspection will be documented in accordance with the Corrective Action Program as discussed in LRA Appendix B Section 2.0 (page B-5).

B.3.1.3 Pipe Wall Thinning Inspection Program

RAI B.3.1.3 - 1

Provide the specific section in the American National Standards Institute (ANSI) B31.7, that will be the basis for calculating the required minimum wall thickness for Unit 1 auxiliary feedwater piping.

FPL Response

As indicated in Table 3.9-4 of the St. Lucie Unit 1 UFSAR, the Auxiliary Feedwater piping is designed in accordance with ANSI B31.7, Nuclear Power Piping, Code Classes 2 and 3. The particular portion of Auxiliary Feedwater piping within the scope of the Pipe Wall Thinning Inspection Program (LRA Appendix B Subsection 3.1.3 page B-14) is designed to ANSI B31.7 Code Class 3 requirements. Accordingly, Chapter 3-II, Part 2: "Pressure Design of Piping Components" of ANSI B31.7 will be used as a basis for calculating the required minimum wall thickness for the subject piping.

RAI B.3.1.3 - 2

Provide the specific section in ASME Code, Section III, that will be the basis for calculating the required minimum wall thickness for the Unit 2 auxiliary feedwater and component cooling water piping.

FPL Response

As indicated in Table 9.2-4 of the St. Lucie Unit 2 UFSAR, the Component Cooling Water piping is designed in accordance with ASME Section III, Class 3 requirements. Similarly, Table 10.4-1 of the St. Lucie Unit 2 UFSAR identifies the design code for Auxiliary Feedwater piping as ASME Section III, Class 2/3. The particular portion of the St. Lucie Unit 2 Auxiliary Feedwater piping within the scope of the Pipe Wall Thinning Inspection Program (LRA Appendix B Subsection 3.1.3 page B-14) is designed to ASME Section III, Class 3 requirements. Accordingly, ND-3600: "Piping Design" of ASME Section III will be used as a basis for calculating the required minimum wall thickness for the subject piping.

RAI B.3.1.3 - 3

In Section B.3.1.3 of the LRA, the applicant states that the pipe wall thinning inspection program is credited as the aging management program for managing the internal loss of material attributed to erosion. Later, in describing the monitoring and trending aspect of the program, the applicant states, "The initial inspection frequency shall be established based on the first inspection results and considering measured wall thickness, corrosion rates, and minimum required wall thickness." Explain the apparent inconsistency between erosion rates and corrosion rates. In addition, explain how those rates are determined.

FPL Response

The apparent inconsistency between the terms "erosion rates" and "corrosion rates" is the result of a typographical error. The text in the Monitoring and Trending portion of the Pipe Wall Thinning Inspection Program (LRA Appendix B Subsection 3.1.3 page B-14) should read..."The initial inspection frequency shall be established based on the first inspection results and considering measured wall thickness, erosion rates, and minimum required wall thickness."

The Pipe Wall Thinning Inspection Program provides for volumetric examination methods to detect loss of material by measuring component wall thickness. This measured wall loss is divided by the time the component has been in service (hours, years, etc.) to determine a conservative erosion rate. This method has been used at St. Lucie in the past and has proven to be an effective method for the determination of erosion rates.

B.3.1.5 Small Bore Class 1 Piping Inspection

B.3.1.5 - 1

In Appendix B, Section 3.1.5, of the LRA, the applicant states that volumetric inspections of small bore Class 1 piping will be conducted on a sampling basis. The one-time inspection program states that locations selected for volumetric inspection will be based on a risk-informed approach that ranks the susceptibility of the small bore Class 1 piping according to two essential elements: (1) a degradation mechanism evaluation to assess the failure potential of the piping system under consideration; and (2) a consequence evaluation to assess the impact on plant safety in the event of a piping failure. Provide the following additional information as the information relates to your program attributes for aging management program B.3.1.5, "Small Bore Class 1 Piping Inspection:"

- Discuss what methodology will be used to determine the greatest potential failure susceptibility locations and discuss how the worst-case consequence locations for the small bore piping will be determined. Discuss how these two essential risk-informed elements will be used to quantify the susceptibility rankings of the small bore Class 1 piping within the scope of the Small Bore Class 1 Piping Inspection.
- Explain which documents or information will be used to define the sample size for the volumetric inspections that will be proposed for the small bore Class 1 piping.

FPL Response

As indicated in LRA Appendix B, Subsection 3.1.5 (page B-19), the Small Bore Class 1 Piping Inspection will occur in the later part of the initial operating period for St. Lucie Units 1 and 2. The timing of this inspection was established to maximize the operating time, and thus, susceptibility to any age-related cracking mechanisms. Any cracking will be evaluated and actions taken as appropriate through the Corrective Action Program. Additionally, the Small Bore Class 1 Piping Inspection will incorporate results and recommendations from industry initiatives. For example, FPL plans on incorporating the applicable results of the Electric Power Research Institute (EPRI) industry initiative to assemble previous guidance on non-destructive examination (NDE) methodologies and to provide recommendations for specific NDE technology and variables for the examination technique. The results of industry initiatives will be evaluated for applicability with respect to examination techniques and acceptance criteria.

As stated in LRA Appendix A1, Subsection 18.1.5 (page A1-34), Appendix A2, Subsection 18.1.5 (page A2-31) and Appendix B, Subsection 3.1.5 (page B-19), FPL will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to its implementation. This report will include a description of the methodologies used to determine the greatest potential failure susceptibility locations and worst-case consequence (risk-informed) locations. In addition, the report will describe the methods used to determine the sample size of the volumetric examinations proposed for the small bore Class 1 piping.

This aging management program is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review (See Safety Evaluation Report Related to License Renewal of Turkey Point Nuclear Plant Units 3 and 4, Section 3.8.7, page 3-203).

B.3.2 EXISTING AGING MANAGEMENT PROGRAMS

B.3.2.1 Alloy 600 Inspection Program

RAI B.3.2.1 - 1

On March 18, 2002, the staff issued NRC Bulletin 2002-01, which requested information relevant to the type of degradation that was detected in the Davis-Besse reactor vessel head in March 2002. The applicant responded to NRC Bulletin 2002-01 in a letter dated April 2, 2002. The Scoping program attribute in the LRA does not reference NRC Bulletin 2002-01 as part of the current licensing basis for the reactor vessel head penetration nozzles. The Detection of Aging Effects program attribute in the LRA implies that only one visual examination of the bare surfaces of each unit's upper reactor vessel head will be performed. If the results of the bare-surface visual examinations indicate the presence of flaw indications, additional bare-surface visual or volumetric examinations of the reactor vessel heads would be performed. As a result of the staff's review of the Operating Experience and Demonstration program attribute, the staff is under the impression that FPL completed the December 2001 visual examinations of the bare surfaces of the Unit 2 reactor vessel head. With respect to the Alloy 600 Inspection Program:

- Update the Scoping program attribute to include your response to NRC Bulletin 2002-01 (dated April 2, 2002, in FPL letter L-2002-061).
- Summarize the scope and results of inservice inspections and augmented examinations that were performed on the Unit 1 and 2 reactor vessel heads. Describe the impact that the inspection results will have on the program attributes for the Alloy 600 Inspection Program.

FPL Response

As discussed in Appendix B, Subsection 3.2.1 of the LRA, FPL will continue to be a participant in the industry programs for managing primary water stress corrosion cracking (PWSCC) in Alloy 600 reactor vessel head penetration (VHP) nozzles. For example, the work performed under the Electric Power Research Institute (EPRI) Material Reliability Program (MRP) and the Nuclear Energy Institute (NEI) is an integral part of the St. Lucie Alloy 600 Inspection Program (LRA Appendix B Subsection 3.2.1 page B-22). In addition, St. Lucie commitments made in response to NRC requests regarding PWSCC of VHP nozzles are considered to be part of the program. Accordingly, the scope of the Alloy 600 Inspection Program includes the St. Lucie responses to NRC Bulletin 2002-01 (FPL letters L-2002-061, dated April 2, 2002 and L-2002-116, dated June 27, 2002). In addition, the Alloy 600 Inspection Program will include those St. Lucie commitments made in response to NRC Bulletin 2002-02, (FPL letter L-2002-185, dated September 11, 2002).

The scope and results of inservice inspections and augmented examinations performed to date on the St. Lucie Units 1 and 2 reactor vessel heads is summarized in the St. Lucie responses to NRC Bulletin 2002-01 (FPL letters L-2002-61 and L-2002-116, referenced above). The results of the visual inspections performed to date do not have an impact on the program attributes for the Alloy 600 Inspection Program. However, commitments made by FPL in response to NRC Bulletin 2002-02 (FPL letter L-2002-185 referenced above) and future inspection results could have an impact on the program and the specific program attributes would be adjusted at that time. The St. Lucie Units 1 and 2 UFSAR Supplements, LRA Appendix A1 Subsection 18.2.1 and Appendix A2 Subsection 18.2.1 (pages A1-35 and A2-32, respectively) will be revised to incorporate FPL commitments in response to the NRC communications identified above.

B.3.2.2 ASME Section XI Inservice Inspection Programs

RAI B.3.2.2 - 1

In Table 3.5-2 of the LRA, the applicant indicates that the containment bellows are covered by the inservice inspection program established in accordance with Section XI, Subsection IWE, of the ASME Boiler and Pressure Code. Recognizing the susceptibility of the bellows to cracking (see NRC Information Notice 92-20) as a result of transgranular stress corrosion cracking (TGSCC), provide the operating experience related to the condition of the bellows at St. Lucie, Units 1 and 2. Also, provide the method used to detect degradation of the bellows.

FPL Response

NRC Information Notice 92-20 "Inadequate Local Leak Rate Testing" addresses circumstances involving local leak rate testing and an instance where the cause of measured leakage was due to bellows cracking apparently for an in-line bellows (i.e., bellows that are an integral part of the process piping system). The events described by the information notice occurred while testing bellows configurations routinely utilized in boiling water reactor type power plants, and the root cause of the identified cracking is not addressed in the notice.

The containment vessel piping penetration bellows that are installed at St. Lucie Units 1 and 2 are predominantly structural type bellows, designed such that the bellows are not subjected to piping operating system parameters (i.e., not part of the process line pressure boundary). Aging management review results (LRA Table 3.5-2, page 3.5-37) concluded that the stainless steel (expansion joint) portions of the penetration bellows exposed to Containment air or Indoor - not air conditioned environments do not experience aging effects requiring management.

St. Lucie plant-specific operating experience has not identified cracking of these bellows as an aging effect requiring management. Bellows that form a portion of the containment leak tight boundary are leak rate tested in accordance with ASME Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2, page B-26 - Appendix J leak rate testing).

RAI B.3.2.2 - 2

In the GALL aging management program XI.S4, "10 CFR Part 50, Appendix J," Section 1, "Scoping of Program," the staff specifies the options for leakage testing of containment isolation valves. The options are to conduct testing (1) under the Type C test of Appendix J, or (2) along with the tests of the systems containing the containment isolation valves. Which option will the applicant implement during the extended period of operation?

FPL Response

Currently, all St. Lucie plant containment isolation valves that require testing under 10 CFR 50, Appendix J, are tested per Appendix J, Option B, Type C test, as part of the ASME Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2 page B-26). Currently there are no plans to change these test methods during the period of extended operation.

RAI B.3.2.2 - 3

Summarize the operating experience related to the leakage rate testing of the pressure-retaining containment components for St. Lucie, Units 1 and 2.

FPL Response

Containment leak-tight verification of the steel components that are part of the leak-tight barrier are conducted at both St. Lucie units as part of the ASME Section XI, Subsection IWE Inservice Inspection Program (LRA Appendix B Subsection 3.2.2.2, page B-26 - Category E-P, Appendix J). Appendix J requires that licensees provide for pre-operational and periodic testing of the leak-tight integrity of the primary reactor containment, systems, and components that penetrate the containment. Appendix J requires that after the pre-operational leakage rate test is conducted, a set of three tests (to provide a measure of reactor containment overall leakage rate) be conducted at equal intervals during each 10-year service period. The Appendix J tests performed at both St. Lucie units during the years of operation have not shown any loss of intended function of the containment steel components that were attributed to loss of material or other aging effects.

There have been 6 Integrated Leak Rate Tests (ILRTs) performed on St. Lucie Unit 1 and 4 ILRTs performed on Unit 2, all of which have been successful. Test report results have been forwarded to the NRC via the FPL correspondence listed below.

St. Lucie Unit 1

- St. Lucie Unit 1 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-75-510 dated October 20, 1975.
- St. Lucie Unit 1 Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-79-214 dated August 7, 1979.
- St. Lucie Unit 1 Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-83-434 dated August 3, 1983.
- St. Lucie Unit 1 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-87-237 dated June 10, 1987.
- St. Lucie Unit 1 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-90-230 dated June 21, 1990.
- St. Lucie Unit 1 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-93-206 dated August 23, 1993.

St. Lucie Unit 2

- St. Lucie Unit 2 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-83-116 dated March 2, 1983.
- St. Lucie Unit 2 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-86-343 dated August 25, 1986.
- St. Lucie Unit 2 Reactor Containment Building Integrated Leak Rate Test Report, submitted to the NRC via FPL letter L-89-230 dated June 28, 1989.
- St. Lucie Unit 2 Reactor Containment Building Integrated Leak Rate Test (ILRT) Report, submitted to the NRC via FPL letter L-92-251 dated September 15, 1992.

B.3.2.5.1 Water Chemistry Control Subprogram

RAI B.3.2.5 - 1

In Section 3.2.5.1 of Appendix B to the LRA, the applicant states that no special one-time inspections are required to verify the effectiveness of the Water Chemistry Control Subprogram for St. Lucie Units 1 and 2. The applicant also states that internal surfaces of components are visually inspected for loss of material and other aging effects during routine and corrective maintenance requiring equipment disassembly. Clarify that those locations inspected during routine and corrective maintenance include representative susceptible locations (such as low flow or stagnant areas). In addition, discuss past findings that demonstrate that routine and corrective maintenance verified the effectiveness of the Water Chemistry Control Subprogram.

FPL Response

Although routine preventive and corrective maintenance inspections do not specifically target components subject to low flow, many of these inspections require component removal and/or disassembly such as valve, pump or heat exchanger overhaul procedures. In the process of disassembly many potential low flow areas, including crevices associated with mechanical joints, are exposed and subject to inspection. It should also be noted that ASME Boiler and Pressure Vessel Code Section XI requires an internal visual examination to determine the condition of Class 1 valve and pump internals at least once each inspection interval. When significant corrosion or degraded parts are identified, the support of materials experts within FPL is typically requested to determine root cause. A review of plant-specific operating experience for the St. Lucie closed water systems was performed to identify any age-related material failures associated with crevice corrosion or inadequate chemistry controls. No instances of crevice corrosion in treated water systems or evidence of an ineffective chemistry control program were identified. This review included past material failures associated with various components including several in stagnant or low flow areas (vent and drain lines and instrument lines). None of the failures associated with stagnant or low flow lines were attributed to crevice corrosion or lack of chemistry controls. Based on the foregoing, the Water Chemistry Control Subprogram (LRA Appendix B Subsection 3.2.5.1 page B-32) is an effective program. Additional information is contained in FPL responses to RAIs 3.3.2-1 and 3.3.2-2 (see FPL letter L-2002-159).

RAI B.3.2.5 - 2

In Section 3.2.5.1 of Appendix B to the LRA, the applicant states that the Water Chemistry Control Subprogram was developed in accordance with the guidance in TR-107396, "Closed Cycle Cooling Water System," published October 1997 by the Electric Power Research Institute (EPRI) and is consistent with the 10 attributes of the AMP X1.M21, "Closed-Cycle Cooling Water System,"" in the Generic Aging Lessons Learned (GALL) report, with the exception that this subprogram does not address surveillance testing and inspection. The applicant further states that the Intake Cooling Water Inspection Program implements the applicable surveillance testing and inspection aspects of the GALL program. The Intake Cooling Water Inspection Program includes inspection of only those closed-cycle cooling water (CCW) system components that are exposed to raw water, which are the CCW heat exchanger tubes, tubesheet channels, and doors. The GALL report recommends inspecting these components and other CCW system components, which are exposed to treated water and susceptible to loss of material. Explain this discrepancy between the Chemistry Control Program, as descriptions in Section 3.2.5.2 of Appendix B to the LRA and the AMP X1.M21 in the GALL report.

FPL Response

Aging Management Program X1.M21, "Closed-Cycle Cooling Water System," of the Generic Aging Lessons Learned (GALL) Report states that the aging management program monitors the effects of corrosion by surveillance testing and inspection (in accordance with standards in EPRI TR-107396, "Closed Cycle Cooling Water System") to evaluate system and component performance. The existing St. Lucie Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram (LRA Appendix B Subsection 3.2.5.2 page B-33), in conjunction with the Intake Cooling Water System Inspection Program (LRA Appendix B Subsection 3.2.10 page B-43) and periodic surveillance testing is consistent with the GALL Closed-Cycle Cooling Water System Program with respect to parameters monitored or inspected. The parameters monitored by the Chemistry Control Program – Closed-Cycle Cooling Water System Subprogram for the purposes of license renewal aging management are based on the recommendations of EPRI TR-107396. Non-chemistry parameters monitored by periodic surveillance testing include pump flow and discharge and suction pressures, heat exchanger flow and inlet and outlet temperatures, and emergency diesel generator performance. The component cooling water heat exchangers are periodically inspected under the Intake Cooling Water System Inspection Program. As part of the aging management review process for Component Cooling Water, a review of St. Lucie plant-specific operating experience was performed to identify any age-related material failures/degradations associated with corrosion due to inadequate chemistry controls. The results of the review identified no instances of material failures or degradation, which supports evidence of an effective chemistry control program. Note that some Component Cooling Water components have been inspected in the past as part of corrective maintenance or the preventive maintenance program (e.g., periodic pump overhauls), and any significant degradation identified during these inspections would have been documented under the plant corrective action program. As such, the St. Lucie Chemistry Control Program - Closed-Cycle Cooling Water System Subprogram, was determined to be an effective program and the need for periodic inspections of other Component Cooling Water components was determined not to be required.

RAI B.3.2.5 - 3

Corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom. Ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring. Identify the locations in the fuel oil components (e.g., fuel oil tank bottoms) at which periodic fuel oil samples are obtained. Indicate when thickness measurements are used to detect aging effects on the tank bottom.

FPL Response

Degradation of the tank bottoms due to accumulation of contaminants has not been experienced at St. Lucie. In order to ensure that contaminants are not accumulating and causing degradation of the diesel fuel oil components, the diesel fuel oil quality is managed by the Chemistry Control Program – Fuel Oil Chemistry Subprogram (LRA Appendix B Subsection 3.2.5.3 page B-34). This program is focused on managing the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC) of the diesel fuel tank internal surfaces and the Emergency Diesel Generator (EDG) fuel supply system.

To ensure purity of the fuel throughout the system, upon receipt of new fuel oil and prior to transferring the oil from the tanker to the storage tanks, fuel is tested to specific ASTM standards, verifying proper API gravity, kinematic viscosity, flash point, appearance and color. In addition, fuel in the storage tanks are sampled and tested at least once every 31 days in accordance with ASTM D2276-83 and by verifying total particulate contamination of less than 10 mg/liter. Prior to obtaining storage tank samples, the tanks are placed on recirculation to ensure that the samples are representative of the bulk fuel oil in the tanks.

Accumulated water is also removed from both the storage tanks as required by the St. Lucie Technical Specifications. Accumulated water from the bottom of the tanks is removed at least once per 92 days. In addition to the removal of water accumulation, per St. Lucie Technical Specification requirements, the storage tanks are drained, cleaned of accumulated sediment, and visually inspected for internal corrosion every 10 years. Thickness measurements of the tank bottoms would only be taken if required as part of corrective actions to address significant loss of material. To date, all of the tanks have been inspected with no indication of aging mechanisms or effects.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

RAI B.3.2.5 - 4

In Section 3.2.5.3 of Appendix B to the LRA, the applicant states that operating experience at St. Lucie Units 1 and 2 has included particulate contamination attributable to a contaminated tanker truck transfer pump and hose. However, no instances of fuel oil system component failures attributable to contamination have been identified. Discuss the corrective action taken to prevent recurrence. Also, discuss the operating experience regarding the effectiveness of the aging management program such that aging degradation, which could lead to the loss of an intended function, will be identified and addressed before it results in age-related failures of the fuel oil system components.

FPL Response

Particulate contamination of the diesel fuel oil storage tanks (DOSTs) was discovered when an off-site contract laboratory identified out of specification particulate contamination in three of the four DOSTs. This event was caused by the use of a contaminated fuel oil tanker truck transfer pump and hose. To prevent recurrence of contamination caused by the contaminated tanker truck transfer pump and hose, the following corrective actions were taken: (1) the chemistry procedure was revised to require flushing the first 100 gallons of diesel fuel oil into drums to ensure cleanliness of the tanker, pump, and discharge hose; (2) a permanent filtration unit was installed at the site which is connected to the fuel oil tanker discharge hose to remove possible contamination after the initial 100-gallon flush; (3) chemistry procedures were revised to correct deficiencies (e.g., use of incorrect solvent in the sampling process). In addition, St. Lucie diesel fuel oil analytical techniques were reviewed by an outside vendor to ensure compliance with ASTM standards.

To ensure that degradation of the diesel fuel oil tank and fuel supply system does not occur, exposure of the internal surfaces to contaminants in the fuel oil is minimized. This is accomplished by implementing the following aging management programs for the Diesel Generator Fuel Oil System:

- Chemistry Control Program – Fuel Oil Chemistry Subprogram (LRA Appendix B Subsection 3.2.5.3 page B-34) provides for monitoring of fuel oil parameters in accordance with ASTM Standards (as specified in the St. Lucie Technical Specifications), addition of biocides to minimize biological activity, addition of stabilizers to prevent biological breakdown of the diesel fuel, and addition of corrosion inhibitors to mitigate corrosion.
- Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) provides for the periodic removal of water from the fuel oil storage tanks and the draining and cleaning of the storage tanks every 10 years.

Based on a review of St. Lucie plant-specific operating experience, with the exception of the particulate contamination described above, no instances of fuel oil component failures attributed to contamination have been identified. Visual inspection of the storage tanks has not identified any degradation due to corrosion or any other mechanism.

B.3.2.8 Fire Protection Program

RAI B.3.2.8 - 1

In Section B.3.2.8, "Scope," of the LRA, the applicant states that the Fire Protection program will manage the aging effects of loss of material due to corrosion. Provide justification for excluding loss of material due to micro-biologically influenced corrosion or biofouling of carbon steel and cast-iron components in fire-protection systems exposed to water.

In addition, clarify the information on page 3.3-11 of the LRA that indicates that the Fire Protection Program is consistent with the corresponding programs in the GALL report.

FPL Response

Loss of material due to micro-biologically influenced corrosion (MIC) was not excluded by FPL as an aging effect requiring management for carbon steel and cast iron components in fire protection systems. As discussed in LRA Appendix C, Section 5.1 (page C-13), MIC was considered an aging mechanism which causes loss of material for systems operating at temperatures less than 210°F and pH less than 10. As a result, the aging management review of Fire Protection identified loss of material due to MIC as an aging effect requiring management for the internal surfaces of the cast iron and carbon steel components exposed to "Raw water-city water." Loss of material due to this aging mechanism is included on LRA Table 3.3-6 (pages 3.3-42 through 3.3-44).

With respect to biofouling, as stated in LRA Appendix C, Section 5.3 (page C-15), biofouling is an aging effect due to an accumulation of macro-organisms. Fire Protection at St. Lucie uses water classified as "Raw water – city water." As stated in LRA Appendix C, Section 4.1.2 (page C-7), this water is potable water -- water that has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purposes of aging management review. Macro-organisms would not be found in this water. Therefore, biofouling is not an aging effect requiring management.

LRA Subsection 3.3.4 (page 3.3-11) incorrectly states that the Fire Protection Program is consistent with the corresponding programs in the GALL report. As stated in LRA Appendix B Section 3.2.8 (page B-39), the Fire Protection Program is plant-specific. Therefore, the list in LRA Subsection 3.3.4 (page 3.3-11) is revised to delete the Fire Protection Program from the list of St. Lucie programs that are consistent with the corresponding programs in the GALL Report, and revised to add the Fire Protection Program to the St. Lucie plant-specific programs list.

<u>RAI B 3.2.8 - 2</u>

In Section B.3.2.8, "Parameters Monitored or Inspected," of the LRA, the applicant states that surface conditions are visually monitored. Provide the percentage for each type of penetration seal that would be inspected during each refueling outage. Also, provide the inspection frequencies for the visual and function tests of fire doors and seals.

<u>FPL Response</u>

As stated in the response to RAI 3.5-3, and based on the information provided in SECY-96-146 and St. Lucie plant-specific operating experience, fire barrier penetration seals do not experience aging effects that would lead to a loss of intended function. This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

However, plant procedures do provide for the inspection of penetration seals. Currently, visual inspection of at least 10% of each type of sealed penetration is performed during each refueling outage. If changes in appearance or degradations are found, a visual inspection of an additional 10% of each type are made. This process continues until a 10% sample with no changes or degradation is found. Samples are selected such that each seal will be inspected at least once every fifteen years.

Fire door inspection is currently conducted every six months.

RAI B.3.2.8 - 3

Discuss your program for internal inspections of fire protection piping as stated in Chapter XI.M27, "Fire Water Systems," of the Gall report. Explain how the program will detect wall thinning due to internal corrosion. Opening the system results in introducing oxygen, that may contribute to the initiation of general corrosion. Explain why the use of non-intrusive means of measuring wall thickness, such as ultrasonic inspection, are not used to manage this aging effect.

FPL Response

As clarified in the above response to RAI B 3.2.8-1, the St. Lucie Fire Protection Program (LRA Appendix B Subsection 3.2.8, page B-39) is plant-specific. Fire Protection at St. Lucie is filled with water classified as "raw water – city water." As stated in LRA Appendix C, Section 4.1.2 (page C-7), this water is potable water. The water has been rough filtered to remove large particles. City water has been purified but conservatively classified as raw water for the purposes of aging management review. Internal conditions are monitored via leakage, flow, and pressure testing. Internal loss of material can be detected by changes in flow or pressure, leakage or by evidence of excessive corrosion products during flushing of the system.

St. Lucie plant-specific operating experience supports the conclusion that past inspections/ overhauls of fire protection components normally exposed to water, such as fire water pumps, hydrants, post indicator and other valves, have not identified degraded conditions of the internal surfaces of adjoining piping requiring corrective action. Additionally, there were no instances of inside diameter initiated corrosion in normally pressurized fire water piping within the scope of license renewal. Thus, the current methods of monitoring internal conditions are adequate and reliable.

This position is consistent with that accepted by the NRC as part of the Turkey Point Units 3 and 4 LRA review.

RAI B.3.2.8 - 4

Discuss the inspection activities that provide the reasonable assurance that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation.

FPL Response

Internal and external conditions for below grade fire protection piping are monitored via leakage, flow and pressure testing. Internal and external loss of material can be detected by changes in flow or pressure, leakage, or by evidence of excessive corrosion products during flushing of the system. St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable for Fire Protection System underground piping.

RAI B.3.2.8 - 5

In Section B.3.2.8, "Operating Experience and Demonstrations," of the LRA, the applicant states that the Fire Protection Program has been subjected to periodic internal and external assessments. Discuss the significant recent enhancements as a result of these assessments. Indicate whether or not these enhancements have received NRC approval.

FPL Response

There have been no recent enhancements to the Fire Protection Program (LRA Appendix B Subsection 3.2.8 page B-39). However, based on recent periodic internal and external assessments, fire protection plant modifications have been implemented including the replacement of all Unit 2 preaction suppression system local control panels with updated equipment, replacements of Unit 1 smoke detectors with new model detectors, replacement of both Control Room fire computers with new fire panels, extended preaction system coverage in the Units 1 and 2 cable loft areas, upgraded Thermolag protection in Units 1 and 2, and upgraded penetration seals (cable tray fire stops) in Unit 2. St. Lucie also performed NFPA Code Reviews of the Suppression and Detection Systems, and, based on the findings, further evaluations and modifications were implemented (e.g., increased radiant heat shield coverage in Unit 1 and 2 Containments and improved weather resistance of exterior smoke detection systems). The NRC reviewed some of the evaluations and modifications described above during the St. Lucie Fire Protection Functional Inspection conducted in 1998. Others have been implemented subsequent to this inspection. With respect to NRC review, all changes to the Fire Protection Program and/or system are reviewed in accordance with 10 CFR 50.59 and Facility Operating Licenses DPR-67 (Unit 1) Section C.(3) and NFP-16 (Unit 2) Section C.3.20.

RAI B.3.2.8 - 6

The 50-year service life of sprinkler heads does not necessarily equal the 50th year of operation in terms of licensing. The service life is defined from the time the sprinkler system is installed and functional. The staff interpretation, in accordance with National Fire Protection Agency (NFPA) 25, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," is that testing should be performed prior to 50 years of sprinkler system service life, not at year 50 of plant operation. The staff position for this approach results in an applicant performing three such inspections over a 60-year period; the first before the end of the current operating term, the second after the 50-year sprinkler head testing, and the third after the first 10-year follow-up sprinkler head testing. Discuss your inspection plans for the sprinkler heads during the current operating term, as well as during the period of extended operation.

FPL Response

For St. Lucie Unit 1, the oldest sprinkler heads were installed approximately one year prior to issuance of the St. Lucie Unit 1 Facility Operating License. Per St. Lucie Units 1 and 2 UFSARs, Appendix 9.5A, the St. Lucie Current Licensing Bases do not include NFPA 25 for testing and inspection of sprinkler heads. However, St. Lucie generally conforms to NFPA guidelines. St. Lucie uses city water (potable) as its water source for Fire Protection. This water was conservatively classified as "raw water" for the purpose of performing aging management reviews even though it is clean and free of contaminants compared to lake or river water used in fire protection systems at other plants. The quality of the water minimizes loss of material, as evidenced by St. Lucie's operating and maintenance experience. A fire protection system annual flush is credited for ensuring the system is clear of scale, debris and foreign material.

For closed head sprinkler systems, procedures verify the systems are in a state of readiness by ensuring proper operation of clapper/inlet valves, all nozzles are unobstructed, and that water and supervisory air pressure are within specifications.

Based on feedback from meetings with NRC staff conducted during the review of the Turkey Point Unit 3 and 4 LRA review and open items identified on previous license renewal applications, St. Lucie proposes to perform testing of wet pipe sprinkler heads following the guidance of NFPA 25 commencing in the year 2026 (50 years from the issuance of the original operating license on Unit 1). This enhancement will be included within the Fire Protection Program (LRA Appendix B Subsection 3.2.8 page B-39).

This position is consistent with that accepted by the NRC during the review of the Turkey Point Units 3 and 4 LRA review.

B.3.2.10 Intake Cooling Water Inspection Program

RAI B.3.2.10 - 1

The periodic surveillance and preventive maintenance program is an existing program that will be enhanced with regard to the scope of specific inspections. Provide applicable frequencies, bases, and the most recent operating history supporting the adequacy of this program for the following components in the intake cooling water system: stainless steel, carbon steel and cast iron intake cooling water pumps; rubber intake cooling water pump expansion joints; and aluminum-bronze pump discharge valves exposed externally to the raw water environment. The applicant provided this information for other components in the intake cooling water system.

FPL Response

As indicated on LRA Table 3.3-9 (pages 3.3-59 and 3.3-62), St. Lucie has no cast iron or carbon steel intake cooling water (ICW) pumps. The pump casings are made of stainless steel or aluminum bronze. The current frequency of inspection for the ICW pumps is 96 months. This frequency is appropriate, based on the operating and maintenance history of these components at St. Lucie. The current frequency of replacement of the Unit 1 ICW pump expansion joints is 120 months. This frequency was also determined to be acceptable based upon past experience. The frequency of these inspections may be adjusted as necessary based on future plant-specific performance and/or industry experience. Note that the Unit 2 ICW pump expansion joints are constructed of stainless steel.

Other than vent, drain, and instrument valves, there are no aluminum bronze valves in ICW, and none are exposed externally to a raw water environment.

RAI B.3.2.10 - 2

For those structures that are inaccessible for inspection through the systems and structures monitoring program, an inspection of structures with similar materials and environments may be indicative of aging effects. Several components in the intake cooling water system credit this program for managing loss of material in the raw water environment. Provide the applicable frequencies, bases, and the most recent operating history supporting the adequacy of this program for the following components in the intake cooling water system: cast iron, carbon steel, bronze, monel, and stainless steel valves, piping, tubing, and fittings; stainless steel orifices; and stainless steel thermowells exposed internally to the raw water environment.

FPL Response

As described in LRA Appendix B, Section 3.2.14 (page B-58), the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping, and fittings at selected locations of Intake Cooling Water (ICW) by leakage inspection to detect the presence of internal corrosion. Loss of material for orifices, thermowells, and tubing/fittings due to internal exposure to raw water is also managed by leakage inspection via the Systems and Structures Monitoring Program as listed in LRA Table 3.3-9 (pages 3.3-60 and 3.3-61). Leakage inspection of ICW orifices, thermowells, and tubing/fittings was inadvertently omitted from the Systems and Structures Monitoring Program description in LRA Appendix B. These locations mostly encompass small bore piping components not addressed by the ICW crawl-through inspections due to access limitations. Evaluations have been performed to show that through-wall leakage equivalent to a sheared 3/4" instrument line and an additional 100 gpm opening from another location will not reduce the ICW flow to the Component Cooling Water heat exchangers below design requirements. The leakage inspection is adequate in managing the aging effects of loss of material for the following reasons:

(a) Maintenance history shows that localized failures of cement lining result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage, which provides adequate time for repairs before the system function is degraded.

(b) For small valves, piping/tubing/fittings, thermowells, and orifices leakage does not affect the system function because the small size of these components limits the leakage. The St. Lucie plant-specific operating experience for these components demonstrates that leakage for this equipment has not been significant.

The leakage inspection is currently performed at least once per 18 months. This frequency is based on St. Lucie plant-specific operating experience. The frequency of inspections may be adjusted as necessary based on future inspection results and industry experience.

RAI B.3.2.10 - 3

Identify and describe the specific plant procedures and applicable documents which contain detailed guidance related to performance monitoring, testing and tube examinations of the heat exchangers. Also provide the acceptance criteria and the bases for acceptance of the inspection results.

FPL Response

The below listed procedures monitor, test, and inspect the heat exchangers.

- Component Cooling Water (CCW) – Normal Operation
- CCW Heat Exchangers Tube Integrity Inspection
- CCW Heat Exchanger Cleaning and Repair

Acceptance criteria with regard to flow and temperature are provided to ensure design basis and technical specification requirements for heat transfer capability are maintained by monitoring CCW heat exchanger performance. Guidelines are provided for cleaning, inspecting, and testing the heat exchangers.

RAI B.3.2.10 - 4

In the UFSAR for St. Lucie Unit 1, the applicant states that the component cooling water heat exchanger components exposed to raw water are protected by sacrificial anodes located in the heat exchangers. Are these sacrificial anodes credited in reducing corrosion or cracking? Identify and describe the program that provides for inspection of these anodes.

FPL Response

Each of the St. Lucie Unit 1 Component Cooling Water (CCW) heat exchangers has sacrificial anodes installed as a preventive measure to minimize the potential for corrosion of parts exposed to raw water. A plant maintenance procedure provides for the periodic inspection/replacement of these sacrificial anodes. However, the aging management review of Intake Cooling Water components did not credit the sacrificial anodes in reducing corrosion or cracking for the CCW heat exchanger components exposed to raw water.

RAI B.3.2.10 - 5

In Section B.3.2.10 of the LRA, applicant states that the internal linings on piping and other components are visually inspected for degradation. What criteria are used to determine which components should be inspected? Do these inspections include inspection of lining on the inside surface of fittings such as elbows? This information is requested because the field experience described in IE Information Notice No. 85-24, "Failures of Protective Coatings in Pipes and Heat Exchangers," indicates that the interior protective lining on elbows are more susceptible to degradation than that on straight piping.

FPL Response

Internal inspections of Intake Cooling Water (ICW) piping and components are normally performed during the refueling outages on a scope and frequency based on past inspection results. The current scope of inspection addresses 100% of the internally accessible components (including linings of fittings such as elbows) and is performed every other refueling interval. Based on St. Lucie plant-specific operating experience, this inspection scope and frequency are adequate to ensure that ICW piping will continue to perform its intended function during the period of extended operation.

Note that the frequency of the inspections may be adjusted as necessary based on inspection results and industry experience.

RAI B.3.2.10 - 6

For the buried or submerged carbon steel piping in intake cooling water system, which is externally exposed to aggressive external environments, the Intake Cooling Water System Inspection Program does not provide sufficient information about how the applicant plans to prevent, mitigate, detect, or trend loss of material caused by corrosion at the outside surface of these piping. Do you plan to use the wall thickness measurements as indicators of loss of material at the external surface of buried and submerged carbon steel piping? If so, then describe how these wall thickness will be measured.

FPL Response

As discussed in LRA Appendix B Section 3.2.10 (pages B-43 and B-44), the Intake Cooling Water System Inspection Program is a plant specific program that includes commitments made in response to GL 89-13 "Service Water System Problems Affecting Safety-Related Equipment." Internal inspections are used to manage loss of material due to external corrosion of buried and submerged piping. Additional nondestructive testing may be utilized to measure external surface condition and the extent of wall thinning based on the evaluation of examination results and as documented in accordance with the corrective action program.

Intake Cooling Water piping is externally coated with a coal tar epoxy to minimize the potential for corrosion. Additionally, this piping is buried in Class 1 fill above ground water elevation such that it is not exposed to aggressive ground water. St. Lucie has not experienced any indications of external loss of material of its buried Intake Cooling Water piping. Should localized degradation of the external coating occur, external corrosion would manifest itself as a corrosion cell. This corrosion cell would ultimately result in though-wall corrosion. As discussed in the response to RAI 3.3.9-3, any potential through-wall leakage resulting form this type of degradation is accommodated by plant design. Early identification of this localized degradation would occur during the periodic 100% internal piping crawl-through inspection. Based upon these considerations, the aging management review of the Intake Cooling Water piping considered external loss of material due to corrosion to be an aging effect requiring management and credited the Intake Cooling Water System Inspection Program for managing this aging effect.

B.3.2.11 Periodic Surveillance And Preventive Maintenance Program

RAI B.3.2.11 - 1

In Section B.3.2.11, "Monitoring and Trending," of the LRA, the applicant states"

> The inspections, replacements, and sampling activities associated with this program are performed on a specific frequency as listed in administrative procedures, and that the results of these activities are documented. The program includes various frequencies depending upon the specific component and aging effect being managed, and plant operating experience.

Since this is an existing program, provide a brief description of how frequently the inspections are conducted and components are replaced. For example, for *Preventive Actions*, the applicant states that preventive measures include charging pump block internal inspection (Unit 2 only), oil sampling and water removal, and replacement of specific structural components and component groups are based on operating experience. In *Parameters Monitored or Inspected*, the applicant states that certain intake cooling water system components are replaced on a given frequency based on operating experience. Identify the specific frequencies of those component inspections and replacements, including how operating experience is used to determine the frequencies.

FPL Response

The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) currently includes inspection frequencies ranging from 31 days to 10 years depending upon the specific component, the aging effect being managed, and plant-specific operating experience.

Examples of inspections that are part of this program and their current frequencies are provided below:

- Inspection of charging pump blocks (Unit 2 only) for cracking due to fatigue is currently performed on a 6 month frequency.
- Inspection of diesel fuel oil storage tanks (DOSTs) for accumulated water is performed on a 92 day frequency for Unit 1 and on a 31 day frequency for Unit 2. This is performed by opening drains on the tanks.
- Oil Sampling of the DOSTs in accordance with ASTM D2276-83 is performed on a 31 day frequency.

Examples of component replacements include intake cooling water pumps and expansion joints, which are scheduled for replacement with new or refurbished equipment on a 96 month and 120 month frequency, respectively.

Operating experience is used to determine preventive maintenance (PM) frequencies. For example, the inspections of charging pump 2A, 2B, and 2C blocks are performed as part of the periodic pump valve inspection/overhaul PM activities. Past inspections of blocks during these PM activities have been effective in identifying initiation of cracking in high stress sites. Based upon the service life of the charging pump valves, the frequencies of these PM activities were determined to provide for an early indication of internal fatigue cracking of the blocks.

Water removal and oil sampling of the DOSTs are performed on a frequency as required by the Plant Technical Specifications. Based upon the condition of emergency diesel components as evidenced by past inspections, the frequency of this PM activity is adequate to preclude aging effects associated with loss of material.

The frequencies of overhauls for the ICW pumps and the replacements of discharge expansion joints have been determined based upon the results of past component inspections and consider vendor recommendations. The frequency of the ICW pump overhauls ensure that coating degradations and loss of material due to exposure to the saltwater environment are adequately managed to preclude loss of intended function of the pumps. Likewise, the frequency for replacement of the discharge expansion joints ensures that cracking due to embrittlement is adequately managed.

The frequencies of these tasks may be adjusted as necessary based on future St. Lucie plant–specific performance and/or industry experience. For example, if an enhanced ICW pump coatings product/installation technique demonstrates increased protection of susceptible pump materials, the frequency of periodic overhauls may be increased provided there are no other limiting factors associated with the current frequency.

RAI B.3.2.11 - 2

The applicant provided limited information regarding the different attributes of the periodic surveillance and preventive maintenance program as far as aging management of the instrument air system components is concerned.

(1) Provide information about whether the program is based on the Instrument Society of America's Standard ISA-S7.0.1-1996, "Quality Standards for Instrument Air." Specifically, discuss whether the moisture content and particulate size in the instrument air are continuously monitored. What are the acceptance criteria for particulate size and oil content in the instrument air? How often is the system sampled to ensure that air quality is maintained?

(2) Provide information about the inspection and testing frequency used for the instrument air system components. Does the program follow the recommendations made by the industry report issued by the Electric Power Research Institute (EPRI) as EPRI NP-7079, "Instrument Air Systems – A Guide for Power Plant Maintenance Personnel," 1990, or its 1998 revision (i.e., EPRI/NMAC TR-108147, 1998)?

FPL Response

Item 1

Instrument Air at St. Lucie was redesigned in the late 1980s to address equipment related problems and industry issues identified by GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment." These modifications included the replacement of the instrument air dryers with more effective desiccant dryers (including prefilter and after filters) and two new air compressors per unit with capacities and purification capabilities recommended by ANSI/ISA-S7.3, "Quality Standard for Instrument Air, Instrument Society of America." Instrument Air for St. Lucie Units 1 and 2 meets the air quality requirements of ANSI/ISA S7.3-1975, Quality Standard for Instrument Air.

The Periodic Surveillance and Preventive Maintenance Program (LRA Appendix B Subsection 3.2.11 page B-46) is not based on the Instrument Society of America's Standard ISA S7.0.1-1996. Although the moisture content and particulate size in Instrument Air are not continuously monitored, performance of the air dryers is monitored regularly via a dryer moisture indicator. The dryers are reconditioned as needed based on this indication. The instrument air compressors are of the oil-free type. Dewpoint is determined annually. Instrument air particulate and oil samples are also taken annually per chemistry department procedures. This frequency is based on the recommendations contained in ISA-RP 7.7 and St. Lucie plant-specific operating experience. The acceptance criteria for instrument air particulate size is three micrometers. The acceptance criteria for oil content is zero w/w or v/v (weight basis or volume basis). The acceptance criteria for dewpoint is 18°F below the minimum local recorded ambient temperature at the plant site.

Item 2

The applicable Instrument Air components (compressors, dryers, receivers, etc.) are inspected on a 26 week interval. The Periodic Surveillance And Preventive Maintenance Program does generally follow several, but not all, of the inspection and testing / frequency recommendations in the EPRI NP-7079, "Instrument Air Systems – A Guide for Power Plant Maintenance Personnel." Based on St. Lucie plant-specific operating experience, this preventive maintenance interval is acceptable.

B.3.2.14 Systems and Structures Monitoring Program

RAI B.3.2.14 - 1

In order for the staff to conclude that the monitoring and trending activities of the Systems and Structures Monitoring Program (SSMP) are adequate to detect the aging of structures and components that credit this program, provide additional information on the inspection intervals and sample sizes used for the SSMP. In particular, provide the inspection intervals and sample sizes used for the systems and structures, listed on page B-57 of the LRA, which credit the SSMP.

FPL Response

As described in LRA Appendix B, Section 3.2.14 (page B-58), the Systems and Structures Monitoring Program (SSMP) employs the visual inspection method. Structures and structural commodities are visually inspected on an area basis, and system commodities and components are visually inspected on a system basis. Conditions documented and evaluated via the Corrective Action Program may employ other methods, such as volumetric examination and computed radiography, to determine the extent of degradation.

The inspection schedule varies depending on the system, structure, or component being inspected. Initially, inspections will be performed on a frequency of five years. However, leakage inspection of Intake Cooling Water will be performed on an 18 month frequency. These frequencies are based on St. Lucie plant-specific operating experience regarding degradation rates and the ability of a structure or component to accommodate degradation without a loss of intended function. The frequency of inspections may be adjusted as necessary based on future inspection results and industry experience.

Accessible components listed in LRA Table 3.5-2 through Table 3.5-16 (pages 3.5-35 through 3.5-93) that are managed by the SSMP will be visually inspected. Initially, the SSMP will not include sampling. However, sampling may be implemented in the future if the inspection results warrant.

RAI B.3.2.14 - 2

The SSMP is an existing program. However, in Section B.3.2.14 of the LRA, the applicant states that enhancements will be made to provide guidance for managing the aging of inaccessible concrete. In particular, the staff notes that below-grade components, such as concrete slabs or building foundations, may be subject to aggressive chemical attack as a result of the chemistry (pH, sulfides, chlorides) of the groundwater. In order for the staff to determine that the SSMP will provide for adequate aging management of inaccessible concrete, provide examples of past inspection findings related to the aging of these components.

FPL Response

As noted in the FPL response to RAI 3.5-1, inspection of accessible concrete surfaces will be included in the Systems and Structures Monitoring Program (SSMP) (LRA Appendix B Subsection 3.2.14 page B-57), however, below groundwater concrete surfaces require specifically tailored inspection criteria. Some interior portions of the Reactor Auxiliary Building (RAB) are below groundwater elevation and accessible. These locations will provide good indication of possible degradation of concrete structures located below groundwater. Therefore, inspection of the interior RAB concrete below groundwater will be included in the SSMP for monitoring below groundwater concrete. Additionally, in accordance with NUREG-1801 (GALL Report), examination of representative samples of below grade concrete, when excavated for any reason, will be included as part of the SSMP.

Inaccessible concrete has been inspected during past excavation activities and no concrete degradation was noted. Specifically, a portion of the below grade Containment Shield Building was exposed during the Unit 1 Steam Generator Replacement Project in 1997. Also, portions of the Unit 1 Cask Crane foundations and the Unit 1 Component Cooling Water structure below grade concrete was exposed during exploratory excavations associated with the Unit 1 Cask Crane replacement in 2002.

RAI B.3.2.14 - 3

In order for the staff to conclude that the SSMP will provide adequate aging management for the systems, structures and components that credit this program, provide specific examples of enhancements and improvements that have been made to the SSMP as a result of previous inspection findings.

FPL Response

Systems, structures and components have been inspected for material condition at the St. Lucie plant for many years. As part of implementation of the Maintenance Rule, baseline inspections were performed in 1996. Periodic inspections continue to be performed as part of the Systems and Structures Monitoring Program (SSMP). Degraded conditions are documented under the Corrective Action Program. As part of the Corrective Action Program, actions to prevent recurrence are identified, such as plant modifications and program enhancements to address the affected item as well as related, generic implications. Additionally, periodic trend evaluations are performed to assess and initiate enhancements to plant programs, including the proposed SSMP.

When trends are identified, they are addressed under the Corrective Action Program. Further evaluation is performed including identification and implementation of programmatic improvements, as required. Programmatic improvements may include adjustment of program scope, frequency, acceptance criteria, and/or corrective actions. This process ensures that applicable aging effects are adequately managed.

Examples of program enhancements due to observed degradation include the increased inspections of the Intake Structure concrete, and at locations where steel components have been more susceptible to corrosion. Also, written guidelines have been issued to provide for inspecting components and determining corrective actions.