**DRAFT RECEIVED MARCH 19, 2003**

L-2003-070
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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
License Renewal Safety Evaluation Report Open Item And Confirmatory Item
Responses And Revised License Renewal Application Appendix A

By letter dated February 7, 2003, the NRC issued the Safety Evaluation Report with Open Items Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2. Attachment 1 to this letter provides responses to the open items and confirmatory items identified in the Safety Evaluation Report. In order to address commitments related to open items, confirmatory items, and other items from previous RAI responses, FPL has prepared a revised Appendix A to the St. Lucie Units 1 and 2 License Renewal Application (LRA) entitled, "Updated Final Safety Analysis Report Supplement." This revised LRA Appendix A also incorporates changes as a result of the LRA annual update (FPL Letter L-2003-071). Attachment 2 describes the changes to LRA Appendix A. Attachment 3 is the revised LRA Appendix A in its entirety.

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
Attachments (3)

Enclosure 2

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

License Renewal Safety Evaluation Report Open Item And Confirmatory Item Responses And Revised License Renewal Application Appendix A St. Lucie Units 1 and 2

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

______ day of _______________, 2003.

_______________________________________________

_______________________________________________
Name of Notary Public (Type or Print)

D. E. Jernigan is personally known to me.

cc: <u>U.S. Nuclear Regulatory Commission, Washington, D.C.</u>
Program Director, License Renewal & Environmental Impacts
Project Manager, St. Lucie License Renewal
Project Manager, St. Lucie

<u>U.S. Nuclear Regulatory Commission, Region II</u>
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**ST. LUCIE UNITS 1 AND 2**
**DOCKET NOS. 50-335 AND 50-389**
**ATTACHMENT 1**
**RESPONSE TO OPEN ITEMS AND CONFIRMATORY ITEMS IDENTIFIED IN SAFETY EVALUATION REPORT RELATED TO LICENSE RENEWAL OF ST. LUCIE UNITS 1 AND 2**

**Open Item 3.0.2.2-1:**

The staff conducted an on-site AMR inspection, which included verification of the applicant's claim that some aging management programs are consistent with the GALL Report. The inspection also verified information concerning the scoping and screening results. The inspection was completed on January 31, 2003, and a report documenting the inspection findings is pending. The inspection findings are necessary to determine the acceptability of the aging management programs that are claimed to be consistent with the GALL report. The staff is in the process of reviewing the results of the AMR inspection findings and will complete its evaluations of these aging management programs and scoping and screening results when the inspection report is issued.

**FPL Response:**

NRC Inspection Report 50-335/2003-03 and 50-389/2003-03 summarizing the results of the AMR inspection was issued March 7, 2003. As stated in the "Summary of Findings" in that report, "This inspection did not identify any "findings" as defined in NRC Manual Chapter 0612." Additionally, there were no open issues identified.

Conclusion

Based on the above, no further action has been identified for FPL. FPL requests that Open Item 3.0.2.2-1 be closed.

**Open Item 3.0.5.7-1:**

This item concerns the detection of wall thinning of FP piping due to internal corrosion. The applicant stated that the 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. The applicant also stated that St. Lucie plant-specific operating experience has shown that the current methods of monitoring internal conditions are adequate and reliable. In accordance with Interim Staff Guidance (ISG)-4, "Aging Management of Fire Protection Systems for License Renewal," the applicant should perform a baseline pipe wall thickness evaluation of the FP piping using a nonintrusive means, such as a volumetric inspection, before the current license term expires. Alternatively, the applicant should provide assurance that adequate wall thickness evaluations on representative piping exist such that a baseline wall thickness evaluation is not necessary.

**FPL Response:**

The response below supercedes in its entirety the response to RAI B.3.2.8-3 transmitted in FPL letter L-2002-241 dated December 23, 2002.

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. The following fire protection procedures are credited for aging management of internal conditions of the Fire Water System:

| TEST | FREQUENCY |
|---|---|
| • Wet pipe sprinkler test | semi-annual |
| • Fire system flush | yearly |
| • D/G fire sprinkler system visual integrity exam | yearly |
| • D/G fire sprinkler system obstruction inspection | yearly |
| • D/G fire sprinkler system automatic valve operation | yearly |
| • D/G fire sprinkler system functional test | yearly |
| • RAB fire sprinkler system functional test | yearly |
| • Yard fire hydrant flow check | yearly |
| • Main transformer water spray test | 18 month |
| • Auxiliary transformer water spray test | 18 month |
| • $H_2$ seal oil water spray test | 18 month |
| • Turbine lube oil storage water spray test | 18 month |
| • 3 year fire protection flow test | 3 year |
| • Fire hose station flow check | 3 year |
| • City Water Storage Tanks interior inspection | 5 year |

With regard to St. Lucie plant-specific operating experience, 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.

During the recent implementation of Fire Water System modifications, ultrasonic pipe wall thickness measurements were taken on stagnant portions of the system, which confirm the good internal condition of the fire main and its branches. These modifications were associated with enhancements identified prior to or during the 1998 NRC Fire Protection Functional Inspection, and included the addition of an automatic suppression system for Thermo-Lag walls and the addition of new hose stations in the Reactor Auxiliary Buildings. Pipe wall thickness measurements were taken on 4 and 6 inch normally stagnant lines prior to welding and confirmed that minimal internal loss of material due to corrosion has taken place (i.e., the pipe wall thicknesses were approximately nominal). Based upon the nominal pipe wall thickness and the measured values for the limiting case, the corrosion rate over 24 years of service is calculated to be approximately 0.3 mils/year. Additionally, if the original pipe wall thickness is conservatively assumed to be nominal plus the manufacturer's fabrication allowance (i.e., +12.5%), the worst case corrosion rate is calculated to be 1.5 mils/year. Based upon this worst case corrosion rate and the measured pipe wall thickness, the projected pipe wall thickness at the end of the extended operating period is 175 mils, well in excess of the ANSI B31.1 Code required minimum wall of 22 mils. Thus, additional pipe wall thickness measurements are not required and 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.

Conclusion

Based on the above, FPL requests that Open Item 3.0.5.7-1 be closed.

**Open Item 3.0.5.10-1:**

Several components in the intake cooling water system credit the Systems and Structures Monitoring Program for managing loss of material in the raw water environment. In RAI B.2.10-2, the staff asked the applicant to justify the adequacy of this program for managing the aging effects on specific components in the intake cooling water system. The staff finds the applicant's response does not adequately address the aging management of the small valves, piping/tubing/fittings, thermowells, and orifices. The applicant, in a letter dated November 27, 2002, provided additional information concerning the materials, operating history, and repair history of the small valves, piping/tubing/fittings, thermowells, and orifices in the intake cooling water system. However, the applicant also relies on leakage detection for aging management of some components. It is the staff's position that leakage detection does not provide adequate aging management because leakage indicates a loss of component intended function.

**FPL Response:**

The response below supercedes the response to RAI 3.3.9-3 transmitted in FPL letter L-2002-222 dated November 27, 2002. This response is being revised to address Open Item 3.0.5.10-1. Specifically, this response provides additional justification for the adequacy of the Systems and Structures Monitoring Program (LRA Appendix B Subsection 3.2.14, page B-57) and the Intake Cooling Water Inspection Program (LRA Appendix B Subsection 3.2.20 page B-43) for managing the internal aging effects of small bore valves, piping/tubing/fittings, thermowells, and orifices in Intake Cooling Water (ICW). This response also provides additional information regarding the use of leakage detection in Chemical and Volume Control (CVCS) as identified in the Systems and Structures Monitoring Program.

As described in LRA Appendix B, Subsection 3.2, the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping, and fittings at selected locations of ICW by leakage inspection to detect the presence of internal corrosion. 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 inch 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 CLB 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 or internal epoxy coating of intake cooling water lines 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 or structural integrity of the line is degraded.

b. For small valves, piping and fittings, leakage does not affect the system function because the small size of these components limits the leakage. These valves and lines are either constructed of corrosion resistant materials (monel, bronze, aluminum bronze), are concrete or rubber lined, or are epoxy coated carbon steel. The mechanical joints in carbon steel lines are the most susceptible locations due the interface between the flange face/gasket and the internal lining/coating. Because the joints in carbon steel lines may be exposed to salt water, a specification was developed to provide for the replacement of these lines with monel on an "as required" basis during inspections or when leaks are identified. To date, approximately 75% of the epoxy coated, small carbon steel piping and fittings, and all of the small valves, have been replaced with corrosion resistant materials. Plant operators walk down ICW as part of normal shift activities, and would note any leaks that were present. When leaks are identified, they are immediately documented under the corrective action program and receive prompt engineering evaluation and corrective actions. The operating and maintenance history of this equipment demonstrates that leakage for this equipment has not been significant.

In addition to the above process, periodic crawl-through inspections of the large bore piping, as described in the Intake Cooling Water Inspection Program, are conducted to identify, evaluate and repair any component degradations. Although no crawl-through inspections can be performed on the small-bore piping, the mechanical joints (i.e., flanged connections) between the small bore and large-bore piping are inspected as part of the crawl-through inspections of the large bore piping. These mechanical joints are representative of other mechanical joints in the small-bore lines and are the most likely locations for corrosion as discussed above. Therefore, the Intake Cooling Water Inspection Program, in conjunction with the Systems and Structures Monitoring Program, provides an effective means of aging management for the internal surfaces of Intake Cooling Water.

Table 3.3-9 of the LRA (pages 3.3-59, 3.3-60, and 3.3-61) is revised as shown below:

**TABLE 3.3-9**
**INTAKE COOLING WATER**

| Component/ Commodity Group [GALL Reference] | Intended Function | Material | Environment | Aging Effects Requiring Management | Program/Activity |
|---|---|---|---|---|---|
| **Internal Environment** | | | | | |
| Valves (strainer bypass, strainer backwash, and spent fuel pool makeup) | Pressure boundary | Carbon steel<br>Cast iron<br>(Unit 1 only) | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Piping/fittings (strainer bypass and strainer backwash)<br>[VII C1. 1.1] | Pressure boundary | Stainless steel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Piping/fittings (strainer bypass, strainer backwash, and spent fuel pool makeup) | Pressure boundary | Stainless steel | Air/gas | None | None required |
| | | Carbon steel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| | | | Air/gas[2] | None[2] | None required |
| Valves (vents, drains, and instrumentation)<br>[VII C1. 2.1] | Pressure boundary | Stainless steel<br>Aluminum bronze<br>Bronze | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Valves (vents, drains, and instrumentation) | Pressure boundary | Carbon steel<br>Monel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Piping/fittings (vents, drains, and instrumentation)<br>[VII C1. 1.1] | Pressure boundary | Stainless steel<br>Aluminum bronze | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |

**TABLE 3.3-9 (continued)**
**INTAKE COOLING WATER**

| Component/ Commodity Group [GALL Reference] | Intended Function | Material | Environment | Aging Effects Requiring Management | Program/Activity |
|---|---|---|---|---|---|
| **Internal Environment** | | | | | |
| Piping/fittings (vents, drains, and instrumentation) | Pressure boundary | Carbon steel<br>Aluminum brass<br>Monel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program(1) |
| | | Fiberglass<br>(Unit 2 only) | Raw water – salt water | Cracking | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program(1) |
| Tubing/fittings | Pressure boundary | Stainless steel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program(1) |

Notes:
1. Inspection of connections between the large bore and small bore piping.
2. Internal air/gas environment is outside air and is applicable to the spent fuel pool makeup lines. Based upon available corrosion allowance and conservative rates, loss of material due to general corrosion is not an aging effect requiring management.

As described in LRA Appendix B Subsection 3.2.14, “Systems and Structures Monitoring Program,” leakage inspections are credited for managing external cracking of selected CVCS valves, piping, and fittings. These leakage inspections only apply to the previously heat traced portions of CVCS (i.e., boric acid make-up lines). A review of St. Lucie plant-specific operating experience for CVCS identified that external stress corrosion cracking (SCC) has occurred in the previously insulated heat traced lines. The SCC was attributed to contaminated insulation due to the water used to wash down external surfaces of piping components. The combination of high halogens (e.g., chlorides) and high temperature (i.e., approximately 180°F) due to heat tracing increased the susceptibility of the lines to SCC. Corrective actions to address this condition included inspection of all susceptible boric acid makeup piping (including liquid penetrant examinations of high chloride concentration areas), replacement of defective portions, and administrative enhancements for cleaning external surfaces of stainless steel piping. Additionally, as part of a boric acid concentration reduction project, CVCS piping insulation has been removed since heat tracing is no longer required. The results of SCC are localized minor leakage (not catastrophic failure of the piping) detectable by periodic visual inspection under the Systems and Structures Monitoring Program. Since the initial identification of SCC and corrective actions taken in 1990, there have only been two occurrences of minor leakage due to external SCC in the previously heat traced lines. One leak occurred in Unit 1 in 1996, and one on Unit 2 in 1998.

Therefore, the Systems and Structures Monitoring Program provides an effective means for aging management of external cracking due to SCC of selected CVCS valves, piping, and fittings.

Conclusion

Based on the above, FPL requests that Open Item 3.0.5.10-1 be closed.

**Open Item 3.1.0.1-1:**

A commitment is requested to implement any recommended inspection methods, inspection frequencies, and acceptance criteria that result from industry initiatives by the CEOG, NEI, or EPRI MRP Integrated Task Group on Inconel materials (including Alloy 600 and Alloy 182/82 materials) that are recommended for managing stress corrosion cracking (including PWSCC) of Inconel components, and are found acceptable by the NRC. A commitment is also requested to implement any further requirements that may result from the staff's resolution of the issue of PWSCC in nickel-based alloy components (including those that may result from the staff's resolution of the industry's responses to NRC Bulletin 2002-02, and/or resolution of the V.C. Summer issue).

**FPL Response:**

As discussed in the St. Lucie License Renewal Application (LRA) Appendix A1 Section 18.2.1, Appendix A2 Section 18.2.1, Appendix B, Subsection 3.2.1 and FPL response to RAI B.3.2.1-1, submitted to the NRC by FPL Letter L-2002-166, St. Lucie will implement the commitments made in response to NRC Bulletins 2001-01, 2002-01, 2002-02, and commitments made in response to any future NRC communications associated with primary water stress corrosion cracking (PWSCC) in nickel-based alloy components. In addition, 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. Changes to the LRA Appendix A UFSAR Supplements are described in the response to Confirmatory Item 3.0.1.1-1.

<u>Conclusion</u>

Based on the above, FPL requests that Open Item 3.1.0.1-1 be closed.

**Open Item 3.1.0.1-2:**

In Florida Power and Light (FPL) Company's response to RAI 3.2.1-1, the applicant states that the Alloy 600 Inspection Program (A600IP) includes commitments made in the applicant's responses to NRC Bulletin 2002-01 (FPL letters L-2002-061 and L-2002-116 dated April 2, 2002, and June 27, 2002, respectively) and NRC Bulletin 2002-02 (FPL letter L-2002-185 dated September 11, 2002). The responses to these Bulletins are specific to degradation that may occur in the St. Lucie reactor vessel heads (RVHs) and associated penetration nozzles and attachment welds. The responses to these Bulletins do not address degradation that may occur in nickel-based alloy components of other Class 1 RCS subsystems (such as those in the St. Lucie pressurizers, steam generators, hot legs, and reactor vessel internals). The applicant should discuss and clarify the inspection programs for the remaining Class 1 nickel-based alloy base metal and weld components (other than RVH penetration nozzles and their attachment welds), taking into account the similarities and differences between susceptibility ranking and inspection methods proposed for the components when compared with those proposed for the RVH penetration nozzles and their associated attachment welds.

**FPL Response:**

As discussed in the St. Lucie License Renewal Application (LRA) Appendix A1 Section 18.2.1, Appendix A2 Section 18.2.1, Appendix B, Subsection 3.2.1, the St. Lucie Alloy 600 Inspection Program includes reactor vessel head penetration nozzles, reactor head vent pipe, pressurizer instrument nozzles and heater sleeves, Reactor Coolant System (RCS) piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray piping fittings, and RCS dissimilar metal welds. For aging management of the Alloy 600 components and welds, the Alloy 600 Inspection Program is performed in conjunction with visual and other examinations performed in accordance with the ASME Section XI IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program.

Conclusion

Based on the above, FPL requests that Open Item 3.1.0.1-2 be closed.

**Open Item 3.1.0.3-1:**

If the risk-informed methodologies for Small Bore Class 1 Piping Inspection AMP are part of a RI-ISI program that is required to be approved under the provisions of 10 CFR 50.55a(a)(3), the potential exists for methodologies to "screen out" the volumetric examinations of the small bore piping based on risk information and therefore eliminate the volumetric examinations proposed for the small bore Class 1 piping components. In LRA Section 18.1.5 of Appendix A1 for St. Lucie 1 and LRA Section 18.1.14 of Appendix A2 for St. Lucie 2, Florida Power and Light Company (FPL) commits to submitting the inspection plan for Class 1 small-bore piping prior to the end of the initial licensing periods for the units. When this inspection plan is submitted to the staff, the staff requests:

- The applicant confirm that the risk-informed methodologies for the Small Bore Class 1 Piping Inspection will be used only to establish the minimum number and locations of the small bore Class 1 piping full-penetration butt welds to be volumetrically examined and will not be used as a basis to eliminate the volumetric examinations for the welds.

- The applicant provide a discussion in the inspection plan describing the risk-informed methodology and addressing how the methodology has been applied to determine the locations and number of small bore piping components for inspection. Confirm that the inspection plan for the small bore piping will include this information when submitted to the staff as part of the FSAR supplements summary descriptions for the Small Bore Class 1 Piping Inspection AMP.

**FPL Response:**

As described in LRA Appendix B Section 3.1.5 (page B-16), Small Bore Piping Inspection, a one-time volumetric examination of a sample of Class 1 piping less than 4 inches in diameter will be performed. The sample (i.e., minimum number and locations) of welds to be examined will be selected by using a risk informed susceptibility approach. This selection method will not be part of the Risk Informed – Inservice Inspection (RI-ISI) program which is approved under the provisions of 10 CFR 50.55a (a)(3). As stated in LRA Appendix A1 Section 18.1.5 (page A1-34) for St. Lucie Unit 1 and LRA Appendix A2 Section 18.1.4 (page A2-31) for St. Lucie Unit 2, FPL will provide the NRC with a report describing the small bore inspection plan prior to implementation of the inspections.

This inspection plan will confirm that the risk informed methodologies for the Small Bore Class 1 Piping Inspection will only be used to establish the minimum number and locations of the small bore piping full penetration butt welds to be volumetrically examined. It will not be used as a basis to eliminate the volumetric examination of the welds. Additionally, this inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. This information will be included as part of the FSAR supplement summary descriptions for the Small Bore Class 1 Piping Inspection Program as described in the FPL response to Confirmatory Item 3.1.0.3-1.

Conclusion

Based on the above, FPL requests that Open Item 3.1.0.3-1 be closed.

**Open Item 3.1.0.5-1:**

The applicant described the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. In accordance with ASTM E185, for current 40-year practice, it is recommended that the last capsule to be removed should receive the same or higher fluence than the peak EOL fluence. Therefore, the applicant should provide updated capsule removal schedules that reflect a capsule to be withdrawn with a predicted fluence equal to or greater than the peak EOL fluence for the extended period of operation for St. Lucie Units 1 and 2.

**FPL Response:**

The predicted 60 year end of life (EOL) peak fluence for St. Lucie Unit 1 is $4.24 \times 10^{19}$ n/cm$^2$ and is based on 52 EFPY of operation. The predicted 60 year EOL peak fluence for St. Lucie Unit 2 is $4.48 \times 10^{19}$ n/cm$^2$ and is based on 55 EFPY of operation. The St. Lucie LRA Updated Final Safety Analysis Report Supplements, Appendix A1 for Unit 1 (page A1-21) and Appendix A2 Unit 2 (page A2-19), contain the revised capsule removal schedules considering the period of extended operation. Capsule location 263$^o$ for Unit 1(the fourth of a five capsule program) is to be removed at approximately 38 EFPY, and capsule location 277$^o$ for Unit 2 is to be removed at approximately 44 EFPY. Based upon these capsule locations, accumulated fluences at 38 and 44 EFPY for Units 1 and 2 respectively, are consistent with the predicted 60 year end of life (EOL) peak values noted above. Note that there will be a fifth capsule scheduled for removal from Unit 1 (83$^o$) that will approximate 1.18 times the 60 year EOL vessel fluence.

The fluence values presented in LRA Tables 4.2-3 and 4.2-4 (pages 4.2-9 and 4.2-10) regarding St. Lucie Units 1 and 2 60 year end of life $RT_{PTS}$ values are based on predicted fluences assuming 60 EFPY of operation. These bounding values of fluence were used for the $RT_{PTS}$ analyses only and do not reflect the predicted 60 year EOL peak fluences based on 52 EFPY for Unit 1 and 55 EFPY for Unit 2.

<u>Conclusion</u>

Based on the above, FPL requests that Open Item 3.1.0.5-1 be closed.

**Open Item 3.1.1.2-1:**

The applicant has not identified in Table 3.1-1 and Section 3.1.1.2 of the LRA that loss of mechanical closure integrity is an applicable effect for the stainless steel or carbon steel non-Class 1 bolting materials as a result of stress relaxation. The applicant should provide the basis for not considering stress relaxation to be an applicable aging effect mechanism for the stainless steel and carbon steel non-Class 1 bolting materials. If loss of mechanical closure integrity due to stress relaxation is considered to be an applicable effect for the stainless steel and carbon steel non-Class 1 bolting materials, the applicant should provide revised AMRs for these bolting materials to reflect that loss of mechanical closure integrity is an applicable effect for these bolting materials and propose an applicable inspection-based AMP to manage loosening of the bolts during the extended periods of operation for the St. Lucie units.

**FPL Response:**

As described in EPRI Guideline TR-104213, "Bolting Joint Maintenance and Application Guide," and EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants" (referenced in the GALL Report), stress relaxation is a design consideration in establishing required pre-load of bolted connections. As discussed below, loss of pre-load due to stress relaxation was evaluated for Class 1 and non-Class 1 bolting materials at St. Lucie.

Appendix C to the LRA summarizes the process for identifying aging effects requiring management for non-class 1 components, including the evaluation of stress relaxation. A reference to LRA Appendix C was inadvertently omitted from LRA Subsection 3.1.1.2 (page 3.1-8) for non-Class 1 Reactor Coolant System piping. Note that with the exception of Section 3.1.1.2, all other sections of the LRA addressing the aging management review of non-class 1 components (e.g., Engineered Safety Features Systems, Auxiliary Systems, Steam and Power Conversion Systems, etc.) referenced Appendix C of the LRA. The process described in Appendix C is based upon industry guidance developed by the Babcock and Wilcox (B&W) Owners Group and was tailored to address St. Lucie materials and environments. Additionally, this guidance incorporates specific aging mechanisms/effects based upon St. Lucie plant-specific operating experience. Stress relaxation and creep were evaluated as potential aging mechanisms in LRA Appendix C, Section 5.6, "Distortion/Plastic Deformation" (page C-18) for non-Class 1 components, and determined not to require aging management. Based upon the materials of construction and operating temperatures, the non-class 1 components were determined not to be susceptible to creep and stress relaxation. Typical bolting material for non-class components is SA-193 Gr. B7.

As discussed in LRA Section 3.1.1.1, "Class 1 Piping", loss of mechanical closure integrity due to stress relaxation was identified as a relevant aging effect that requires management for bolted closures. The pre-load in the bolts (or studs) can relax at sufficiently high temperatures after prolonged service. The loss of pre-load can lead to reactor coolant pressure boundary leakage at the mechanical joint. The temperature threshold for this effect is material dependent. The ASME Boiler and Pressure Vessel Code, Section III Appendices, notes that stress relaxation may occur at temperatures of 700ºF and greater for bolts complying with A-193 Grade B7, and at 500ºF or greater for studs complying with certain classes of SA/A-540 Gr. B23 or B24 materials. Since some of the bolting materials utilized in Class 1 Reactor Coolant System (RCS) components are constructed from SA/A-540 Gr B23 or B24, the aging management review for Class 1 RCS components conservatively considered loss of mechanical closure integrity due to stress relaxation as an aging effect requiring management and credited the ASME Section XI Inservice Inspection Program to manage this aging effect.

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

Conclusion

Based on the above, FPL requests that Open Item 3.1.1.2-1 be closed.

**Open Item 3.1.2.2-1:**

The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 materials and are welded to the low-alloy steel pressurizer surge and spray nozzles using Alloy 182/82 weld metals. Industry experience has demonstrated that these weld materials are susceptible to PWSCC. In its AMR provided October 3, 2002, the applicant concluded that there are no applicable aging effects for the pressurizer surge and spray nozzle thermal sleeves because the applied loads on the thermal sleeves are low. The attachment welds for the pressurizer surge and spray nozzle thermal sleeves may contain high residual stresses that result from solidification of the weld metal from the molten state. Therefore, the staff concludes that the attachment weld for the pressurizer surge and spray nozzle thermal sleeves may be susceptible to cracking as a result of PWSCC, and that the applicant's supplemental AMR for the pressurizer thermal sleeves needs to be revised to include cracking as an applicable effect for the components.

**FPL Response:**

The response below supercedes in its entirety the response to RAI 2.3.1-2 transmitted in FPL letter L-2002-144 dated October 3, 2002.

Thermal sleeves are included in the design of the pressurizer surge and spray nozzles and are designed to protect these nozzles from thermal shock. Since the thermal sleeves are not part of the nozzle pressure boundary, their failure would not affect the nozzles pressure boundary intended function. However, the thermal sleeves are included in the fatigue analyses of the pressurizer surge and spray nozzles and these analyses have been identified as a time-limited aging analysis (TLAA) and dispositioned in LRA Subsection 4.3.1 (page 4.3-2). Accordingly, the thermal sleeves are considered to be within the scope of license renewal, pursuant to 10 CFR 54.4(a)(2) and require an aging management review.

The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 and are exposed to an environment of treated water – primary. The only aging effect requiring evaluation for the thermal sleeves is cracking. Cracking due to stress corrosion or primary water stress corrosion was determined not to be an aging effect requiring management based on the design/fabrication of the sleeves. The thermal sleeves for Units 1 and 2 are constructed from either Alloy 600 pipe or rolled Alloy 600 plate material with a longitudinal seam weld. The sleeves are then machined, inserted into their respective nozzles, and expanded to secure them in place. There are no thermal sleeve attachment welds to the nozzles or any other pressurizer pressure boundary parts. Should cracking of a thermal sleeve longitudinal seam weld occur, the sleeve would spring open relieving the principal stresses and would remain captured by the nozzles. Therefore, the sleeve would continue to perform its intended function. Note that since there is no thermal sleeve weld to the nozzle or any other pressure boundary parts, there is no mechanism for the propagation of a crack to impact pressure boundary intended function. As mentioned above, cracking due to fatigue has been identified as a TLAA and is addressed analytically in LRA Subsection 4.3.1. Accordingly, there are no aging effects requiring management for the thermal sleeves.

Note that this conclusion is consistent with that included NUREG-1801, Generic Aging Lessons Learned (GALL) Report. Pressurizer thermal sleeves are included in Chapter IV of the GALL Report, Item C2.5.5. As indicated in the GALL Report table, the aging effect/mechanism identified for the thermal sleeves is cumulative fatigue damage/fatigue. The GALL Report further states that fatigue is a TLAA for the period of extended operation and further refers to NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, Section 4.3 "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1). No additional aging effects are identified in the GALL Report for pressurizer thermal sleeves.

Conclusion

Based on the above, FPL requests that Open Item 3.1.2.2-1 be closed.

**Open Item 3.6.2.1-1:**

Operating experience, as discussed in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants," identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connections surfaces can result in fuse holder failure. On this basis, fuse holders, including both the insulation material and the metallic clamps are subject to both an AMR and AMP for license renewal. Typical plant effects observed from fuse holder failure due to aging have resulted in challenges to safety systems, cable insulation failure due to over-temperature, failure of the containment spray pump to start, a reactor trip, etc. Therefore, managing age-related failure of fuse holders would have a positive effect on the safety performance of a plant. Information Notices 91-78, 87-42, and 86-87 are examples that underscore the safety significance of fuse holder and the potential problems that can arise from age-related fuse holder failure. The staff disagreed with the applicant that there were no aging effects requiring management for fuse holders.

**FPL Response:**

At the NRC public meeting on November 6, 2002, FPL was requested to provide details of the St Lucie Units 1 and 2 aging management review (AMR) of fuse holders, and to provide a commitment to address a revised interim staff guidance (ISG) document regarding fuse holders. Subsequent to that meeting, on March 4, 2003, the NRC issued ISG-5 on the identification and treatment of electrical fuse holders for license renewal. The Staff position stated in ISG-5 is as follows:

> "Consistent with the requirements specified in 10 CFR 54.4(a), fuse holders (including fuse clips and fuse blocks) are considered to be passive electrical components. Fuse holders would be scoped, screened, and included in the aging management review (AMR) in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This staff position only applies to fuse holders that are not part of a larger assembly, but support safety-related and non safety-related functions in which the failure of a fuse precludes a safety function from being accomplished [10 CFR Part 54.4(a)(1) and (a)(2)]. Examples are fuses that are used as protective devices to ensure the integrity of containment electrical penetrations when they are challenged by electrical faults, or as isolation devices between Class 1E and non-Class 1E electrical circuits to ensure that the safety function is not compromised as a result of faults in the non-Class 1E circuits. An appropriate aging management program (AMP) should be adopted to manage the effects of aging where necessary."

With regard to the AMR of fuse holders, as stated in FPL's response to RAI 2.5-1, fuse holders that were not part of a larger, active assembly were scoped, screened, and determined to be subject to an AMR consistent with the ISG. The only fuse holders determined to require an AMR were those installed to address the requirements of Regulatory Guides 1.63 and 1.75 to provide double isolation for non-safety related loads powered from safety related power supplies. These fuse holders are installed in isolation panels located in the Reactor Auxiliary Buildings in rooms classified as "mild environment" areas (e.g., electrical equipment rooms, etc.). The aging effects associated with the isolation panel enclosures (NEMA Type 2, 4, and 12) are managed by the Systems and Structures Monitoring Program (LRA Appendix B Subsection 3.2.14 page B-57). As provided in LRA Section 3.6 (pages 3.6-1 through 3.6-16), the AMR for connections (including the fuse holders in the panels above) addressed applicable aging mechanisms including moisture and oxidation, corrosion, chemical contamination, mechanical stresses including vibration and tensile stresses, electrical transients, thermal cycling, fatigue, radiation and heat on the connecting surfaces. The AMR also addressed adverse localized environments. The AMR concluded that there were no aging effects requiring management for electrical connections, including the fuse holders associated with the panels noted above. Details of the AMR for the fuse holders are provided below.

<u>Moisture, Chemical Contamination, Oxidation, Corrosion,</u>

As stated in LRA Subsection 3.6.1.1.1 (page 3.6-2) and DOE Cable AMG, Section 3.7.2.1.3, 3% of all low-voltage metal connector failures were identified as being caused by moisture intrusion. In each case, the source of moisture was precipitation. Based on the total number of reported connector failures in the DOE Cable AMG, moisture intrusion accounted for only 10 failures in all of the operating plants in the United States. The fuse holders at St. Lucie that require an AMR are protected from external sources of moisture by two barriers. For the first barrier, the panels in which the subject fuse holders are installed are located in rooms inside the reactor auxiliary buildings classified as “mild environment” areas. These rooms protect the panels from the weather, and there are no sources of potential mechanical system leakage in proximity to the panels. For the second barrier, the fuse holders are located in closed NEMA Type 2, 4, and 12 enclosures, some of which are double enclosures. With regard to internal moisture (i.e., formation of condensation), a review of St. Lucie plant-specific operating experience did not reveal any instance aging as a result of the formation of condensation internal to the panels in the reactor auxiliary buildings.

For chemical contamination, the fuse holders are protected, as described above, by their location and design.

With regard to oxidation and corrosion, the St. Lucie fuse holders requiring an aging management review are either manufactured by Bussmann (previously Underwriters Safety Device Co.) or General Electric Co. The Bussmann fuse holders are style J60030-1CR and the General Electric fuse holders are type EK-1D style 9F61AEB301. The clips of these fuse holders are manufactured from copper or copper alloy plated with a corrosion resistant material (tin or silver) to protect the base metal from oxidation and provide for low electrical resistance. The tin and silver plating process is used extensively in the industry to protect both ferrous and nonferrous surfaces from corrosion. Based upon recent inspections of the Bussmann fuse blocks performed the week of March 10, 2003, the surface condition of the fuse clips show no signs of corrosion and still retain their bright metal surface finish even after 20 years of service. Additionally, there was no evidence of moisture. These fuse holders are representative of other low voltage fuse holders at St. Lucie. Because of the excellent corrosion resistance of these platings in an indoor environment, no corrosion rate data for indoor (i.e., sheltered) environment could be located. Note that silver is one of eight noble elements and as stated in reference (b), “These metals are unique in their nobility and for the most part offer industry corrosion resistance unmatched in base metals and their alloys”. However, reference (a) provides some ASTM corrosion rate data of commercial tin exposed to atmospheric (i.e., outdoor, unsheltered) conditions that demonstrates its excellent corrosion resistance. In a rural outdoor environment the average corrosion rate after 10 years was approximately 2 hundredths of a mil/year (0.00049mm/yr). For a marine outdoor environment the corrosion rate after 10 years was .09 mils/year (0.0023 mm/year). Even in these harsh outdoor conditions, the corrosion rate is very small. This data supports the conclusion that for an indoor sheltered environment the corrosion rate of these fuse clips is not significant. This conclusion is further supported by the material condition of the fuse holders recently inspected.

Therefore, oxidation and/or corrosion do not result in aging effects requiring management for St. Lucie fuse holders requiring an aging management review.

<u>Mechanical Stresses, Electrical Transients, Thermal Cycling, Fatigue</u>

For mechanical stresses, electrical transients and thermal cycling associated with the fuse holders at St. Lucie, as stated in LRA Subsection 3.6.1.1.2, these mechanisms do not result in aging effects requiring management for the following reasons:

- Mechanical stress due to forces associated with electrical faults and transients is mitigated by the fast action of circuit protective devices at high currents. However, mechanical stress due to electrical faults is not considered an aging mechanism since such faults are infrequent and random in nature.
- Vibration is induced in fuse holders by the operation of external equipment, such as compressors, fans, and pumps. Since there are direct sources of vibration for the fuse holder panels, and the panels are mounted separately on their own support structure on concrete walls, vibration is not an applicable aging mechanism.
- By design and their location, the fuse holders are not subject to aging effects associated with thermal cycling.

Based on FPL's review of NUREG-1760, the only aging mechanism not explicitly addressed in the LRA for fuse holders is wear/fatigue due to repeated insertion and removal of fuses. For St. Lucie, the fuse holders subject to an AMR are those associated with fuses that are not routinely removed for maintenance and/or surveillance. When these circuits need to be de-energized, power is removed at the safety related power supplies (motor control centers, power panels, etc.).

<u>Radiation, Heat</u>

The fuse holder panels are installed in rooms classified as "mild environment" areas where there are no significant sources of radiation or heat.

As an additional check, FPL reviewed Information Notices (IN) 86-87, 87-42, and 91-78 for applicability to the fuse holders at St. Lucie.

For IN 86-87, the loose fuse holder was associated with a potential transformer (PT) circuit fuse on an emergency bus which blew when a breaker was racked out. Note that although the IN describes a loss of offsite power and reactor trip, neither was attributed to the blown fuse.

For IN 87-42, the failure was associated with poor PT fuse contact. In this case, the fuses have moveable contacts mounted to the PT fuse compartment door so that when the door is opened, the contacts disconnect.

For IN 91-78, the deformed fuse holder was associated with a closing coil circuit on a circuit breaker.

FPL does not consider the above INs applicable to the fuse holders requiring an AMR at St. Lucie because of differences in usage, design and construction.

Based on the information provided above, FPL concludes that there are no aging effects requiring management for fuse holders requiring an AMR for St. Lucie Units 1 and 2.

<u>Conclusion</u>

Based on the above, FPL requests that Open Item 3.6.2.1-1 be closed.

References:

(a) Metals Handbook Ninth Edition, Volume 13 Corrosion, " Corrosion of Tin and Tin Alloys", page 771, Table 1

(b) Metals Handbook Ninth Edition, Volume 13 Corrosion, " Corrosion of the Noble Metals", page 793

**Open Item 4.6.4-1:**

The staff is in the process of reviewing Topical Report WCAP-15973-P; Class 2 Proprietary Calculation CN-CI-02-60; and the applicant's January 8, 2003, relief request for the St. Lucie half nozzle designs. These documents represent the most up-to-date current licensing basis (CLB) for the TLAA on the St. Lucie alloy 600 half-nozzle repairs. The acceptability of TLAA 4.6.4 is pending acceptable approval of these documents. The FSAR Supplement summary descriptions for TLAA 4.6.4, "Alloy 600 Instrument Nozzle Repairs," as given in Sections 18.3.8 of LRA Appendix A1 and 18.3.7 of LRA Appendix A2, do not currently reflect that these documents are part of the CLB for the TLAA on the alloy 600 instrument nozzle repairs. In order to ensure that the FSAR Supplement summary descriptions for this TLAA are up to date, the applicant should supplement the FSAR Supplement summary descriptions, as given in Section 18.3.8 of Appendix A1 and Section 18.3.7 of Appendix A2 to the LRA, to include a reference to Topical Report WCAP-15973-P; Class 2 Proprietary Calculation CN-CI-02-60; and the January 8, 2003, relief request for St. Lucie half nozzle designs.

**FPL Response:**

As stated in FPL responses to RAI 4.6.4-1 and 4.6.4-2 (FPL letter L-2002-222 dated November 27,2002), due to issues identified in Combustion Engineering Owners Group (CEOG) Topical Report CE-NPSD-1198-P, St. Lucie Units 1 and 2 no longer credits this Topical Report or the revision WCAP-15973-P. A plant-specific analysis CN-CI-02-69 (submitted with FPL letter L-2002-222) of the small bore nozzles located in the hot leg piping and the pressurizers for St. Lucie Units 1 and 2 was completed using plant-specific data. This analysis bounds the Class 1 fatigue design requirements of St. Lucie Units 1 and 2.

St. Lucie LRA Appendix A, Updated Final Safety Analysis Report Supplement is revised as follows:

**Unit 1 Appendix A1**

Section 18.3.8 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

The fourth paragraph in Section 18.3.8 (page A1-47) beginning "CEOG Topical Report …" is replaced in its entirety by the following paragraph:

> CEOG Topical Report CE NPSD-1198-P was submitted to the NRC February 15, 2001 to obtain generic approval of the Alloy 600/690 nozzle repair/replacement programs. The CEOG report provides a bounding flaw evaluation that covers all small diameter Alloy 600/690 nozzle repairs in accordance with ASME Section XI requirements. As a result of issues identified in this Topical Report, a plant-specific analysis CN-CI-02-69 of the small bore nozzles located in the hot leg piping and the pressurizers was completed using plant-specific data. These nozzle locations where half-nozzle or similar repairs would be utilized, thereby leaving flaws in the original weldment, which could potentially grow into adjacent ferritic material. Postulated flaws were assessed for the flaw growth and flaw stability as specified in the ASME Code Section XI. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Unit 1 UFSAR. This analysis bounds the Class 1 fatigue design requirements of St. Lucie Unit 1. As discussed in Section 18.3.2.1, review of actual plant operation concludes that the existing design cycles and cycle frequencies are conservative and bounding for the

period of extended operation. Note that Topical Report WCAP-15973 has been issued to revise CEOG Topical Report CE-NSPD-1198-P.

**Unit 2 Appendix A2**

Section 18.3.8 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

The fifth paragraph in Section 18.3.7 (page A2-44) beginning “CEOG Topical Report …” is replaced in its entirety by the following paragraph:

CEOG Topical Report CE NPSD-1198-P was submitted to the NRC February 15, 2001 to obtain generic approval of the Alloy 600/690 nozzle repair/replacement programs. The CEOG report provides a bounding flaw evaluation that covers all small diameter Alloy 600/690 nozzle repairs in accordance with ASME Section XI requirements. As a result of issues identified in this Topical Report, a plant-specific analysis CN-CI-02-69 of the small bore nozzles located in the hot leg piping and the pressurizers was completed using plant-specific data. These nozzle locations where half-nozzle or similar repairs would be utilized, thereby leaving flaws in the original weldment, which could potentially grow into adjacent ferritic material. Postulated flaws were assessed for the flaw growth and flaw stability as specified in the ASME Code Section XI. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Unit 2 UFSAR. This analysis bounds the Class 1 fatigue design requirements of St. Lucie Unit 2. As discussed in Section 18.3.2.1, review of actual plant operation concludes that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation. Note that Topical Report WCAP-15973 has been issued to revise CEOG Topical Report CE-NSPD-1198-P.

<u>Conclusion</u>

Based on the above, FPL requests that Open Item 4.6.4-1 be closed.

**Confirmatory Item 2.3.3.7-1:**

On October 3, 2002, the applicant provided a response to RAI 2.3.3-4 concerning the spent fuel pool makeup lines from the intake cooling water system. At the request of the staff, the applicant agreed to remove the paragraphs in its response that assessed the plant design for the spent fuel pool makeup lines from the intake cooling water system and to state that the makeup lines meet the scoping requirement of 10 CFR 54.4(a)(1).

**FPL Response:**

The response below supercedes the response to RAI 2.3.3-4 transmitted in FPL letter L-2002-144 dated October 3, 2002. This response is being revised to address Safety Evaluation Report (SER) Confirmatory Item 2.3.3.7-1.

Section 9.2.3 of the original SER for St. Lucie Unit 1 states that a fire hose can be connected to the seismic Category I Intake Cooling Water (ICW) at two points to provide makeup, and that the applicant would provide the results of an analysis of the potential for damage to the stored fuel by use of this salt water. The original NRC SER stated further that if NRC review indicated that unacceptable damage could be caused, the fuel exposed to salt water would not be reloaded into the reactor, and that, based on this requirement, the design was acceptable. The results of the further NRC review are discussed in Supplement 1 to the original SER. Section 9.2.3 of Supplement 1 to the original SER states that this evaluation was performed and that for the anticipated time that the salt water makeup would be in use, no unacceptable corrosion of fuel elements or support structures would occur. Based on additional information provided, the NRC also concluded that it would be unlikely that the sea water method of cooling would be needed since several other makeup sources are available.

Based on the above, the ICW makeup source to the Spent Fuel Pool meets the scoping requirements of 10 CFR 54.4 (a)(1) for spent fuel pool cooling, and FPL requests that Confirmatory Item 2.3.3.7-1 be closed.

**Confirmatory Item 3.0.2.2-1:**

The applicant claims that several of its aging management programs (AMPs) are consistent with specific AMPs in the Generic Aging Lessons Learned (GALL) Report. In Appendix B of the LRA, the applicant describes the AMPs that are consistent with the GALL Report and identifies the specific GALL Report AMPs. However, the information concerning the specific GALL Report AMPs is not included the FSAR supplements in Appendix A of the LRA. The applicant agreed to include a reference to specific GALL Report AMPs in the FSAR supplements concerning the AMPs that are consistent with the GALL Report.

**FPL Response:**

For the St. Lucie Aging Management Programs that are consistent with the NUREG 1801 Generic Aging Lessons Learned (GALL) Report, the St. Lucie FSAR Supplements, LRA Appendix A1 for Unit 1 and Appendix A2 for Unit 2 will be revised to include a reference to the GALL Report Aging Management Program. All other aging management programs at St. Lucie are plant-specific.

Appendix A1 will be revised as follows:

18.1.6 THERMAL AGING EMBRITTLEMENT OF CASS PROGRAM

This program is consistent with the ten attributes of aging management program X1.M12, “Thermal Aging Embrittlement of Cast Austenetic Stainless Steel (CASS)” specified in NUREG 1801 GALL Report, (April 2001).

18.2.2.1 ASME SECTION XI, SUBSECTIONS IWB, IWC, AND IWD INSERVICE INSPECTION PROGRAM

This program is consistent with the ten attributes of aging management program X1.M1, “ASME Section XI Inservice Inspections, Subsections IWB, IWC and IWD” specified in NUREG 1801, GALL Report (April 2001) with the following clarification. This program credits ASME Code Case N-509, which allows alternate examination categories for certain integrally welded attachments and has been approved for use at St. Lucie.

18.2.2.2 ASME SECTION XI, SUBSECTIONS IWE INSERVICE INSPECTION PROGRAM

This program is consistent with the ten attributes of aging management programs X1.S1, “ASME Section XI, Subsection IWE” and X1.S4, “10 CFR Part 50 Appendix J” specified in NUREG 1801, GALL Report (April 2001).

18.2.2.3 ASME SECTION XI, SUBSECTIONS IWF INSERVICE INSPECTION PROGRAM

This program is consistent with the ten attributes of aging management program X1.S3, “ASME Section XI, Subsection IWF” specified in NUREG 1801, GALL Report (April 2001).

18.2.3 BORAFLEX SURVEILLANCE PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M22, “Boraflex Monitoring” specified in NUREG 1801, GALL Report (April 2001).

18.2.4 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M10, "Boric Acid Corrosion" specified in NUREG 1801, GALL Report (April 2001).

18.2.5 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program – Water Chemistry Control Subprogram is consistent with ten attributes of aging management program X1.M2, "Water Chemistry" specified in NUREG 1801, GALL Report (April 2001) except that the GALL program credits inspection of select components to verify the effective ness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the period of extended operation. No special one-time inspections are required to be performed at St. Lucie. The Chemistry Control Program – Closed-Cycle Cooling Water System Chemistry subprogram is consistent with the ten attributes of aging management program X1.M21 Closed-Cycle Cooling Water System" specified in NUREG 1801, GALL Report (April 2001) except that the program does not address surveillance testing and inspection. The Intake Cooling Water Inspection Program Section 18.2.10 implements the applicable surveillance testing and inspection aspects of NUREG 1801, GALL program. The Chemistry Control Program – Fuel Oil Chemistry Subprogram is plant-specific.

18.2.6 ENVIRONMENTAL QUALIFICATION PROGRAM

This program is consistent with the ten attributes of aging management programs X.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" specified in NUREG 1801, GALL Report (April 2001).

18.2.9 FLOW ACCELERATED CORROSION PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M17, "Flow-Accelerated Corrosion" specified in NUREG 1801, GALL Report (April 2001).

18.2.13 STEAM GENERATOR INTEGRITY PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M19, "Steam Generator Tube Integrity" specified in NUREG 1801, GALL Report (April 2001).

Appendix A2 will be revised as follows:

18.1.5 THERMAL AGING EMBRITTLEMENT OF CASS PROGRAM

This program is consistent with the ten attributes of aging management program X1.M12, "Thermal Aging Embrittlement of Cast Austenetic Stainless Steel (CASS)" specified in NUREG 1801, GALL Report (April 2001).

### 18.2.2.1 ASME SECTION XI, SUBSECTIONS IWB, IWC, AND IWD INSERVICE INSPECTION PROGRAM

This program is consistent with the ten attributes of aging management program X1.M1, “ASME Section XI Inservice Inspections, Subsections IWB, IWC and IWD” specified in NUREG 1801, GALL Report (April 2001) with the following clarification. This program credits ASME Code Case N-509, which allows alternate examination categories for certain integrally welded attachments and has been approved for use at St. Lucie.

### 18.2.2.2 ASME SECTION XI, SUBSECTIONS IWE INSERVICE INSPECTION PROGRAM

This program is consistent with the ten attributes of aging management programs X1.S1, “ASME Section XI, Subsection IWE” and X1.S4, “10 CFR Part 50 Appendix J” specified in NUREG 1801, GALL Report (April 2001).

### 18.2.2.3 ASME SECTION XI, SUBSECTIONS IWF INSERVICE INSPECTION PROGRAM

This program is consistent with the ten attributes of aging management program X1.S3, “ASME Section XI, Subsection IWF” specified in NUREG 1801, GALL Report (April 2001).

### 18.2.3 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M10, “Boric Acid Corrosion” specified in NUREG 1801, GALL Report (April 2001).

### 18.2.4 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program – Water Chemistry Control Subprogram is consistent with ten attributes of aging management program X1.M2, “Water Chemistry” specified in NUREG 1801, GALL Report (April 2001) except that the GALL program credits inspection of select components to verify the effective ness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the period of extended operation. No special one-time inspections are required to be performed at St. Lucie. The Chemistry Control Program – Closed-Cycle Cooling Water System Chemistry subprogram is consistent with the ten attributes of aging management program X1.M21 Closed-Cycle Cooling Water System” specified in NUREG 1801, GALL Report (April 2001) except that the program does not address surveillance testing and inspection. The Intake Cooling Water Inspection Program Section 18.2.10 implements the applicable surveillance testing and inspection aspects of NUREG 1801, GALL program. The Chemistry Control Program – Fuel Oil Chemistry Subprogram is plant specific.

### 18.2.5 ENVIRONMENTAL QUALIFICATION PROGRAM

This program is consistent with the ten attributes of aging management programs X.E1, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” specified in NUREG 1801, GALL Report (April 2001).

18.2.8 FLOW ACCELERATED CORROSION PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M17, “Flow-Accelerated Corrosion” specified in NUREG 1801, GALL Report (April 2001).

18.2.12 STEAM GENERATOR INTEGRITY PROGRAM

This program is consistent with the ten attributes of aging management programs X1.M19, “Steam Generator Tube Integrity” specified in NUREG 1801, GALL Report (April 2001).

Based on the above, FPL requests that Confirmatory Item 3.0.2.2-1 be closed.

**Confirmatory Item 3.0.5.1-1:**

Section 18.1.2 of Appendix A1 and Section 18.1.1 of Appendix A2 of the LRA provide the applicant's FSAR supplement for the Galvanic Corrosion Susceptibility Inspection Program at St. Lucie. The program descriptions are consistent with the material contained in Section 3.1.2 of Appendix B of the LRA, with the exception of the areas of Acceptance Criteria and Inspection Technique. The applicant needs to revise the FSAR supplements to describe these two attributes consistent with the SER.

**FPL Response:**

The St. Lucie Units 1 and 2 FSAR Supplements (LRA Appendix A1 and A2) will be revised to identify that the baseline examinations will be either visual inspections or volumetric examinations. In addition, the FSAR Supplements will be revised to state that the evaluation of the inspection results will consider the minimum required wall thickness consistent with the applicable design codes.

St. Lucie Unit 1 FSAR Supplement (LRA Appendix A1) Section 18.1.2 is replaced in its entirety by the following paragraph:

18.1.2 GALVANIC CORROSION SUSCEPTIBILITY INSPECTION PROGRAM

The Galvanic Corrosion Susceptibility Inspection Program manages the aging effect of loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. The program involves selected, one-time inspections on the surfaces of piping and components with the greatest susceptibility to galvanic corrosion. Baseline examinations (visual inspection or volumetric examinations) in select systems will be performed and evaluated to establish if the corrosion mechanism is active. Evaluation of the inspection results will consider the minimum required wall thickness for the component consistent with the applicable design codes. Based on the results of these inspections, the need for follow-up examinations or programmatic corrective actions will be established. The program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

St. Lucie Unit 2 FSAR Supplement (LRA Appendix A2) Section 18.1.1 is replaced in its entirety by the following paragraph:

18.1.1 GALVANIC CORROSION SUSCEPTIBILITY INSPECTION PROGRAM

The Galvanic Corrosion Susceptibility Inspection Program manages the aging effect of loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. The program involves selected, one-time inspections on the surfaces of piping and components with the greatest susceptibility to galvanic corrosion. Baseline examinations (visual inspection or volumetric examinations) in select systems will be performed and evaluated to establish if the corrosion mechanism is active. Evaluation of the inspection results will consider the minimum required wall thickness for the component consistent with the applicable design codes. Based on the results of these inspections, the need for follow-up examinations or programmatic corrective actions will be established. The program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

Based on the above, FPL requests that Confirmatory Item 3.0.5.1-1 be closed.

**Confirmatory Item 3.0.5.4-1:**

Section 18.2.4 of Appendix A1 and Section 18.2.3 of Appendix A2 of the LRA provide the applicant's FSAR supplement for the Boric Acid Wastage Surveillance Programs at St. Lucie. The staff reviewed the sections to verify that the information in the FSAR supplement provides an adequate summary of the program activities required by 10 CFR 54.21(d). The staff identified that the applicant needs to modify the FSAR supplement descriptions of the Boric Acid Wastage Surveillance Program to include portions of the waste management system within the scope of license renewal. The applicant needs to revise the FSAR supplements to describe these changes consistent with the SER.

**FPL Response:**

LRA Appendix A1 St. Lucie Unit 1 FSAR Supplement Section 18.2.4 and LRA Appendix A2 St. Lucie Unit 2 FSAR Supplement Section 18.2.3 contain the following paragraph:

> Portions of the Waste Management System within the scope of license renewal are not currently included in the Boric Acid Wastage Surveillance Program. As such, the scope of the program will be enhanced to include these components and to provide for the inspection and evaluation of adjacent structures and components when leakage is identified. This enhancement will be completed prior to the end of the initial operating license term for St. Lucie Unit 1(2).

This paragraph identifies the commitment to include Waste Management System components within the scope of license renewal in the Boric Acid Wastage Surveillance Program. Therefore, no change to the FSAR Supplements is required.

Based on the above, FPL requests that Confirmatory Item 3.0.5.4-1 be closed.

**Confirmatory Item 3.1.0.1-1:**

Sections 18.2.1 of Appendices A1 and A2 of the LRA provide the applicant's FSAR supplement for the A600IP. The program descriptions are consistent with the material contained in Section 3.2.1 of Appendix B to the LRA, with possible exceptions in the areas of Detection of Aging Effects, Monitoring and Trending, and Acceptance Criteria. These may be revised by the applicant's responses to Open Items 3.1.0.1-1 Parts 1 and 2. The applicant needs to revise the FSAR supplements to describe these attributes consistent with the SER.

**FPL Response:**

Note that Open Item 3.1.0.1-1 does not contain two parts. However, there are two Open Items 3.1.0.1-1 and 3.1.0.1-2 that address the Alloy 600 Inspection Program.

As a result of the responses to Open Items 3.1.0.1-1 and 3.1.0.1-2, LRA Appendix A1 Section 18.2.1 and LRA Appendix A2 Section 18.2.1 Updated FSAR Supplements will be revised to add the following paragraph:

> The Alloy 600 Inspection Program will implement FPL commitments in response to NRC communications associated with primary water stress corrosion cracking (PWSCC) of Inconel materials (including Alloy 600 and Alloy 182/82 materials). In addition, this program will be maintained consistent with the recommendations of the Combustion Engineering Owners Group (CEOG), Nuclear Energy Institute (NEI), and Electric Power Research Institute (EPRI) Material Reliability Program (MRP).

Based on the above, FPL requests that Confirmatory Item 3.1.0.1-1 be closed.

**Confirmatory Item 3.1.0.3-1:**

Section 18.1.5 of Appendix A1 and Section 18.1.4 of Appendix A2 of the LRA provide the applicant's FSAR supplement for the Small Bore Class 1 Piping Inspection AMP. The program descriptions are consistent with the material contained in Section 3.1.5 of the appendix to the LRA, with possible exceptions in the areas of Detection of Aging Management Effects and Monitoring and Trending. These program attributes may be revised by the applicant's responses to Open Item 3.1.0.3-1 and 3.1.0.3-2. The applicant needs to revise the FSAR supplements to describe these attributes consistent with the SER.

**FPL Response:**

Note that this Confirmatory Item references Open Items 3.1.0.3-1 and 3.1.0.3-2. Review of the SER did not identify any Open Item 3.1.0.3-2.

St. Lucie FSAR Supplements, LRA Appendix A1 Section 18.1.5 for Unit 1 and LRA Appendix A2 Section 18.1.4 for Unit 2 are replaced in their entirety by the following paragraphs:

**Unit 1 Appendix A1**

18.1.5 SMALL BORE CLASS I PIPING INSPECTION

A volumetric inspection of a sample of small bore Class 1 piping will be performed to determine if cracking is an aging effect requiring management during the period of extended operation. This one-time inspection will address Class 1 piping less than 4 inches in diameter. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established. FPL will provide a report describing this inspection plan prior to its implementation. The inspection plan will confirm that the risk-informed methodologies will only be used to establish the minimum number and locations of small bore piping full penetration butt welds to be volumetrically examined. It will not be used as a basis to eliminate the volumetric examination of the welds. Additionally, this inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 1.

**Unit 2 Appendix A2**

18.1.4 SMALL BORE CLASS I PIPING INSPECTION

A volumetric inspection of a sample of small bore Class 1 piping will be performed to determine if cracking is an aging effect requiring management during the period of extended operation. This one-time inspection will address Class 1 piping less than 4 inches in diameter. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established. FPL will provide a report describing this inspection plan prior to its implementation. The inspection plan will confirm that the risk-informed methodologies will only be used to establish the minimum number and locations of small bore piping full penetration butt welds to be volumetrically examined. It will not be used as a basis to eliminate the volumetric examination of the welds. Additionally, this inspection plan will describe the risk-informed methodology and address how the methodology has been applied to determine the locations and number of small bore piping components for inspection. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 2.

Based on the above, FPL requests that Confirmatory Item 3.1.0.3-1 be closed.

**Confirmatory Item 3.6.2.1-1:**

The applicant committed to provide a description of Non-EQ Cables and Connections AMP to be added in the FSAR supplements in Appendix A of the LRA.

**FPL Response:**

The FSAR Supplements for the St. Lucie Units 1 and 2 will be revised to incorporate the Containment Cable Inspection Program. For Unit 1, LRA Appendix A1, Subsection 18.1.7 and for Unit 2, LRA Appendix A2, Subsection 18.1.6 will be added as follows:

**Unit 1 Appendix A1**

18.1.7 CONTAINMENT CABLE INSPECTION PROGRAM

The Containment Cable Inspection Program manages the potential aging of non-EQ cables and connections. This program includes non-EQ cables and connections associated with sensitive low-level signal circuits. The only non-EQ cables and connections associated with sensitive low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the neutron detectors. This aging management program consists of periodic visual inspection of accessible non-EQ cables and connections within the scope of license renewal located in the containment that may be installed in adverse localized environments, and review of calibration tests results for indication of age related degradation of cables associated with the neutron detectors. The inspections will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

**Unit 2 Appendix A2**

18.1.6 CONTAINMENT CABLE INSPECTION PROGRAM

The Containment Cable Inspection Program manages the potential aging of non-EQ cables and connections. This program includes non-EQ cables and connections associated with sensitive low-level signal circuits. The only non-EQ cables and connections associated with sensitive low-level signal circuits within the scope of license renewal for St. Lucie are those associated with the neutron detectors. This aging management program consists of periodic visual inspection of accessible non-EQ cables and connections within the scope of license renewal located in the containment that may be installed in adverse localized environments, and review of calibration tests results for indication of age related degradation of cables associated with the neutron detectors. The inspections will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

Based on the above, FPL requests that Confirmatory Item 3.6.2.1-1 be closed.

**Confirmatory Item 4.3.1-1:**

The applicant stated that the Inservice Inspection Program would be used to manage the aging of the pressurizer surge line during the period of extended operation. The applicant plans to use the results of the Inservice Inspection Program to develop an approach for addressing environmental assisted fatigue of the surge line. If the applicant selects the approach of using an inspection program, the inspection details including scope, qualification, method, and frequency shall be provided to the NRC for review prior to the period of extended operation. The staff finds that the applicant's proposed options are acceptable to address environmentally assisted fatigue of the pressurizer surge lines during the period of extended operation in accordance with 10 CFR 54.21(c)(1). However, in accordance with 10 CFR 54.21(d), these options need to be included in the FSAR supplements.

**FPL Response:**

The FSAR Supplements for the St. Lucie Units 1 and 2 will be revised to incorporate the options for monitoring environmentally assisted fatigue of the pressurizer surge lines, if required, identified in LRA Subsection 4.3.3 (page 4.3-7) Environmentally Assisted Fatigue. For Unit 1, LRA Appendix A1, Subsection 18.2.2.1 (page A1-35) and for Unit 2, LRA Appendix A2, Subsection 18.2.2.1 (page A2-32), the second paragraph will be replaced in its entirety with the following:

**Unit 1 Appendix A1**

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require VT-1 inspections of the core stabilizing lugs and core support lugs and to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue. If inspections of pressurizer surge line welds identify indications, the results of the inspections will be utilized to assess the appropriate approach for addressing environmentally assisted fatigue of the surge lines. The approach developed could include one or more of the following:

- Further refinement of the fatigue analyses to lower the Cumulative Usage Factors (CUFs) to below 1.0, or
- Repair of the affected locations, or
- Replacement of the affected locations, or
- Management of the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC.

This action will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

**Unit 2 Appendix A2**

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require VT-1 inspections of the core stabilizing lugs and core support lugs and to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue. If inspections of pressurizer surge line welds identify indications, the results of the inspections will be utilized to assess the appropriate approach for addressing environmentally assisted fatigue of the surge lines. The approach developed could include one or more of the following:

- Further refinement of the fatigue analyses to lower the Cumulative Usage Factors (CUFs) to below 1.0, or
- Repair of the affected locations, or
- Replacement of the affected locations, or
- Management of the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC.

This action will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

Based on the above, FPL requests that Confirmatory Item 4.3.1-1 be closed.