# 4.5 METAL CONTAINMENT AND PENETRATION FATIGUE

## 4.5.1 METAL CONTAINMENT FATIGUE

NUREG-1800 [Reference 4.5-1], Section 4.6, addresses TLAAs for metal containments. For completeness, NUREG-1800, Section 4.6 is addressed in this application, although no TLAAs exist for the St. Lucie Units 1 and 2 Containment Vessels.

The St. Lucie Units 1 and 2 Containment Vessels are fabricated from welded steel plate to provide an essentially leak-tight barrier. Design criteria applied to the steel vessels assure that the specified leak rate is not exceeded under the design basis accident conditions. The Containment Vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III. No fatigue analysis was required for the Containment Vessels based on the applicable design codes. Additionally, a review determined that fatigue analysis is not required for the Containment Vessels for the period of extended operation based on the applicable design codes. Therefore, fatigue is not a TLAA for the St. Lucie Units 1 and 2 Containment Vessels.

### 4.5.2 PENETRATION FATIGUE

Containment penetration bellows are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The containment penetrations are categorized as follows:

- Type I Those which must accommodate considerable thermal movements (hot penetrations)
- Type II Those which are not required to accommodate thermal movements (cold penetrations)
- Type III Those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV Containment sump recirculation suction lines
- Type V Fuel transfer tubes

Type I and Type III Penetrations

The thermal fatigue design limits of the Type I and Type III containment penetration bellows are bounded by the thermal fatigue design limits of their associated piping systems. The piping systems associated with Type I and Type III penetration bellows have been evaluated in Subsections 4.3.1 and 4.3.2, and found acceptable for the period of extended operation. The 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

Type II and Type IV Penetrations

Type II penetrations are cold penetrations and Type IV penetrations are only used in post accident scenarios. As such, these penetrations do not require a thermal fatigue analysis. The 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

Type V Penetrations

Since the Units 1 and 2 fuel transfer penetrations are not subject to elevated temperatures, they are not subject to thermal fatigue and thus meet the requirements for 7000 thermal cycles. The 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation.

The analyses associated with the containment penetration bellows fatigue have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

### 4.5.3 REFERENCES

4.5-1 NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," U. S. Nuclear Regulatory Commission, April 2001.

# 4.6 PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

## 4.6.1 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A Leak-Before-Break (LBB) analysis was performed for Combustion Engineering designed NSSSs, which included St. Lucie Units 1 and 2 [Reference 4.6-1]. The LBB analysis was performed to show that any potential leaks that develop in the Reactor Coolant System primary coolant loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. As documented in the March 5, 1993, NRC letter to FPL [Reference 4.6-2], the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie Units are bounded by the Combustion Engineering Owners Group (CEOG) analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of St. Lucie Units 1 and 2.

The aging effects that must be addressed during the period of extended operation include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the Reactor Coolant System loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel (CASS) components. This effect results in a reduction in fracture toughness of the material.

A review by the NSSS supplier concluded that the LBB analysis used conservative material toughness properties relative to correlations developed for fully aged cast stainless steel, which bounds the extended period of operation. Therefore the thermal aging assumptions used for the CASS piping do not satisfy one of the six criteria for a TLAA (i.e., it does not involve a time-limited assumption defined by the current 40-year operating term) and no additional evaluation is required for the period of extended operation.

The LBB fatigue crack growth analysis assumes 40-year design cycles. The plant design cycles discussed in Subsection 4.3.1 are consistent with those utilized in the LBB fatigue crack growth analysis and bound the period of extended operation. Fatigue crack growth for the period of extended operation is negligible.

The Reactor Coolant System primary loop piping LBB fatigue crack growth analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

## 4.6.2 CRANE LOAD CYCLE LIMIT

The following cranes have load cycle assumptions that result in the fatigue analyses being TLAAs.

- Reactor Building Polar Cranes
- Refueling Machine and Hoist (Unit 2 only)
- Reactor Containment Building Auxiliary Telescoping Jib Cranes
- Fuel Transfer Machine (Unit 2 only)
- Spent Fuel Handling Machine (Unit 2 only)
- Refueling Canal Bulkhead Monorail (Unit 2 only)
- Cask Storage Pool Bulkhead Monorail (Unit 2 only)
- Intake Structure Bridge Cranes

The St. Lucie Units 1 and 2 cranes listed above meet the criteria of CMAA-70 "Specifications for Electric Overhead Traveling Cranes," [Reference 4.6-3] as noted in the NRC NUREG-0612 safety evaluations [References 4.6-4 and 4.6-5]. Cranes designed in accordance with CMAA-70 are acceptable for at least 20,000 to 200,000 load cycles. Therefore, the St. Lucie Units 1 and 2 cranes are acceptable for at least 20,000 load cycles.

The St. Lucie cranes are used primarily during refueling outages. Occasionally, cranes make lifts at or near their rated capacity. However, most crane lifts are substantially less than their rated capacity. At St. Lucie, the Unit 2 spent fuel handling machine is bounding for load cycle analysis.

The spent fuel handling machine is used primarily to move fuel assemblies during refueling cycles and is subject to the most loading cycles at or near its rated capacity. Considering a three-batch fuel management scheme, which assumes one third of the core is replaced at each refueling (every 18 months), and a full core off-load every ten-years, the number of lifts performed in 60 years is projected to be less than 7100.

Since the spent fuel handling machine load cycle analysis bounds the other St. Lucie cranes within the license renewal scope, all St. Lucie cranes considered in this evaluation are adequate for expected load cycles over the period of extended operation. In addition, because crane gearing and shafting fatigue lives are related to load lifts (fatigue life design per CMAA-70), the crane gearing and shafting are also adequate for the period of extended operation.

Crane fatigue life and structural integrity have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

### 4.6.3 UNIT 1 CORE SUPPORT BARREL REPAIR

TLAAs were identified for the St. Lucie Unit 1 reactor vessel internals core support barrel (CSB) repair.

During the 1983 St. Lucie Unit 1 refueling outage, the CSB and thermal shield assembly were observed to be damaged. The thermal shield was permanently removed and the CSB was repaired at the thermal shield support lug locations. Four lugs were separated from the CSB and through-wall cracks were adjacent to some damaged lug areas. Through-wall cracks were arrested with crack arrestor holes, non-through-wall cracks were machined out, and lug tear out areas were machined and patched as necessary. The crack arrestor holes were sealed by inserting expandable plugs.

Analysis of the CSB repair method was performed by the NSSS supplier to demonstrate that the repair patches and expandable plug designs were acceptable for the remaining (40-year) life of the plant consistent with ASME code allowable stresses.

A post-repair inspection of the CSB lug area repairs was performed, in 1984, to verify proper installation of the plugs and provide a baseline for comparison of data obtained during future inspections. In accordance with commitments to the NRC [Reference 4.6-6], the CSB repair areas were visually and mechanically inspected in 1986, after one cycle of operation. The inspection report [Reference 4.6-7] concluded that the CSB was in the same condition as it was during the baseline inspection and was acceptable for long-term service with only visual inspections required in the future. A 10-year inservice inspection was performed during the 1996 refueling outage, with emphasis placed on visual inspection of the CSB lug repair areas. No abnormal changes were observed in the repaired CSB lug areas based on comparisons to the 1984 and 1986 inspections.

The analyses and follow-up inspection reports for the repaired CSB and the expandable plugs were screened against the six TLAA criteria. It was determined that two specific elements of the repair qualify as TLAAs: 1) fatigue analysis of the CSB middle cylinder; and 2) acceptance criteria for the CSB expandable plugs' preload based on irradiation induced stress relaxation.

As discussed in Subsection 4.3.1, the 40-year design cycles bounds the extended period of operation. Therefore the CSB fatigue analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The CSB repair plugs are of an expandable design that allows the plugs to be preloaded against the CSB. Preload is required to provide proper seating of the plugs and patches and to prevent movement of the plugs due to hydraulic drag loads. The original evaluation of plug design preload verified that the design preload was sufficient to accommodate normal operating hydraulic loads and thermal deflections for the original operating life of the plant.

The original CSB plug preload analysis was revised for increased, 60-year EOL, fluence as an irradiation-induced relaxation input. The analysis concluded that all the repair plug flange deflection measurement readings are sufficient to meet the minimum required values and maintain the plugs' preload. The CSB repair plugs will therefore perform their intended function for the period of extended plant operation.

The CSB plug preload relaxation analysis has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 4.6.4 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

Small diameter Alloy 600 nozzles, such as pressurizer and Reactor Coolant System hot-leg instrumentation nozzles in Combustion Engineering designed PWRs have developed leaks or partial through-wall cracks as a result of PWSCC. The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the "half nozzle" weld repair has been used to repair selected Alloy 600 instrument nozzles. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

St. Lucie Units 1 and 2 have experienced instances of Alloy 600 instrument nozzle leakage over the lives of the plants. Four Unit 2 pressurizer steam space instrument nozzles and one Unit 1 Reactor Coolant System hot-leg instrument nozzle were repaired with the half nozzle technique, due to leakage and indications.

A fracture mechanics analysis was submitted to the NRC [Reference 4.6-8] to support the St. Lucie Unit 2 pressurizer steam space half nozzle repairs performed in 1994. The fracture mechanics analysis justified the acceptability of indications in the "J" weld based on a conservative postulated flaw size and flaw growth considering the applicable design cycles. The analysis concluded that the postulated flaw size in the instrument nozzle was acceptable for the remaining design life of the plant (30 years, or 75% of the original 40-year plant design life). Consequently, only 75% of the original design cycles was assumed in the flaw growth analysis. However, this analysis has been superseded by a subsequent analysis that considered 100% of the original design cycles, as discussed below.

A half nozzle repair was implemented on a Unit 1 Reactor Coolant System hot-leg instrumentation nozzle in April 2001. In response to NRC questions regarding this repair, FPL [Reference 4.6-9] documented that the indications in the "J" weld were bounded by the fracture mechanics analysis provided in CEOG Topical Report CE NPSD-1198-P [Reference 4.6-10]. FPL also documented in that response that the CEOG topical report is applicable to the Unit 2 pressurizer steam space nozzle repairs performed in 1994.

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. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Units 1 and 2 UFSARs. This generic analysis bounds the Class 1 fatigue design requirements of St. Lucie Units 1 and 2. As discussed in Subsection 4.3.1, review of actual plant operation concludes that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the flaw growth analysis of the Unit 1 Reactor Coolant System hot-leg and the Unit 2 pressurizer steam space Alloy 600 instrument nozzle repairs have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

### 4.6.5 REFERENCES

4.6-1 Combustion Engineering Report CEN-367-A, "Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems," Combustion Engineering, February 1991.

4.6-2 NRC Letter, "St. Lucie Units 1 and 2 - Application of Leak-Before Break Technology to Reactor Coolant System Piping," March 5, 1993.

4.6-3 CMAA Specification No. 70 (CMAA-70), "Specifications for Electric Overhead Traveling Cranes," Crane Manufacturers Association of America, Inc., 1988.

4.6-4 Miller, J. R. (NRC) letter to Williams, J. W. Jr. (FPL), "St. Lucie Unit 1 - Control of Heavy Loads, Phase I," March 4, 1985.

4.6-5 Miller, J. R. (NRC) letter to Williams, J. W. Jr. (FPL), "St. Lucie Unit 2 - Control of Heavy Loads, Phase I," April 2, 1985.

4.6-6 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1 - Reactor Vessel Internals and Thermal Shield; Plant Recovery Program Final Integrity and Stability of Internals - Conclusions and Findings," L-84-29, February 10, 1984.

4.6-7 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1 - Thermal Shield Recovery Program Final Core Support Barrel Inspection Report (Post-Cycle 6)," L-86-181, April 25, 1986.

4.6-8 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 2, In-Service-Inspection Plan, Second Ten-Year Interval, Revised Stress and Fracture Mechanics Evaluations, Pressurizer Instrument Nozzles - Supplement," L-95-220, August 2, 1995, with attached Babcock and Wilcox (B&W) Evaluation 32-1235128-02, "FM Analysis of St. Lucie Pressurizer Instrument Nozzle," Revision 2.

4.6-9 FPL letter to U. S. Nuclear Regulatory Commission, "St. Lucie Unit 1 - In-Service-Inspection Program. Third Ten-Year Interval - Replacement of RCS Hot Leg Instrument Nozzle RC-126," L-2001-131, May 24, 2001.

4.6-10 CEOG Letter (CEOG-01-052) to U. S. Nuclear Regulatory Commission, February 15, 2001, with attached CEOG Topical Report CE NPSD-1198-P, "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs," Revision 0.

# APPENDIX A

## UPDATED UFSAR SUPPLEMENT

Since St. Lucie Units 1 and 2 have separate Updated Final Safety Analysis Reports (UFSARs), a separate UFSAR Supplement has been prepared for each Unit. The St. Lucie Unit 1 UFSAR Supplement is provided as Appendix A1 and the St. Lucie Unit 2 UFSAR Supplement is provided as Appendix A2 to this License Renewal Application.

# APPENDIX A1

## UNIT 1 UPDATED FSAR SUPPLEMENT

# INTRODUCTION

This Appendix contains the St. Lucie Unit 1 UFSAR Supplement required by 10 CFR 54.21(d). The St. Lucie Units 1 and 2 License Renewal Application (LRA) contains the technical information required by 10 CFR 54.21(a) and (c). Chapter 3 and Appendix B of the LRA provide descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Chapter 4 of the LRA contains the evaluations of the time-limited aging analyses (TLAAs) for the period of extended operation. These LRA sections have been used to prepare the program and activity descriptions that are contained in the UFSAR Supplement.

This UFSAR Supplement will be incorporated into the St. Lucie Unit 1 UFSAR following issuance of the renewed operating license for St. Lucie Unit 1. Upon inclusion of the UFSAR Supplement in the St. Lucie Unit 1 UFSAR, changes to the descriptions of the programs and activities for their implementation will be made in accordance with 10 CFR 50.59 and St. Lucie Plant's NRC commitment management program.

# ST. LUCIE UNIT 1 UFSAR

# CHAPTER 1 CHANGES

lateral motion of the tubes. The control element assemblies (CEAs) consist of Inconel clad boron carbide absorber rods which are guided by Zircaloy tubes located within the fuel assembly. The core consists of 217 fuel assemblies loaded with multiple U-235 enrichments.

The reactor vessel and its closure head are fabricated from manganese moly steel internally clad with stainless steel. The vessel and its internals are designed so that the integrated neutron flux (E > 1 ~~greater than 1.0~~ Mev) at the vessel wall will be less than ~~$1.91 \times 10^{19}$~~ $4.7 \times 10^{19}$ n/cm$^2$ ~~nvt~~ over a ~~40~~ 60-year period.

The internal structures include the core support barrel, the core support plate, the core shroud, and the upper guide structure assembly. The core support barrel is a right circular cylinder supported from a ring flange from a ledge on the reactor vessel. The flange carries the entire weight of the core. The core support plate transmits the weight of the core to the core support barrel by means of vertical columns and a beam structure. The core shroud surrounds the core and minimizes the amount of coolant bypass flow. The upper guide structure provides a flow shroud for the CEAs and prevents upward motion of the fuel assemblies during pressure transients. Lateral motion limiters or snubbers are provided at the lower end of the core support barrel assembly.

The reactor coolant system is arranged as two closed loops connected in parallel to the reactor vessel. Each loop consists of one 42-inch ID outlet (hot) pipe, one steam generator, two 30-inch ID inlet (cold) pipes and two pumps. An electrically heated pressurizer is connected to the hot leg of one of the loops and a safety injection line is connected to each of the four cold legs.

The reactor coolant system operates at a nominal pressure of approximately 2235 psig. The reactor coolant enters near the top of the reactor vessel, and flows downward between the reactor vessel shell and the core support barrel into the lower plenum. It then flows upward through the core, leaves the reactor vessel, and flows through the tube side of the two vertical U-tube steam generators where heat is transferred to the secondary system. Reactor coolant pumps return the reactor coolant to the reactor vessel.

The two steam generators are vertical shell and U-tube units. The steam generated in the shell side of the steam generator flows upward through moisture separators and scrubber plate dryers which reduce the moisture content to less than 0.2 percent. All surfaces in contact with the reactor coolant are either stainless steel or NiCrFe alloy in order to minimize corrosion.

The reactor coolant is circulated by four electric motor driven single-suction vertical centrifugal pumps. The pump shaft leakage is minimized by mechanical seals. Each pump motor is equipped with an anti-reverse mechanism to prevent reverse rotation of any pump that is not in operation.

### 1.2.3.2 Engineered Safety Features and Emergency Systems

Engineered safety features systems protect the public and plant personnel in the highly unlikely event of an accidental release of radioactive fission products from the reactor system, particularly as the result of a LOCA. The safety features function to localize, control, mitigate, and terminate such accidents to hold exposure levels below applicable limits.

~~1-2.6~~ 1.2-6 Amendment No. ~~16, (1/98)~~ [LATER]

# ST. LUCIE UNIT 1 UFSAR

# CHAPTER 3 CHANGES

CHAPTER 3

LIST OF TABLES (Cont'd)

### 3.1.31 CRITERION 31 - FRACTURE PREVENTION OF REACTOR COOLANT PRESSURE BOUNDARY

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

DISCUSSION

Carbon and low-alloy steel materials which form part of the pressure boundary meet the requirements of the ASME Code, Section III, paragraph N-330 at a temperature of + 40ºF. The actual nil-ductility transition temperature (NDTT) of the materials has been determined by drop weight tests in accordance with ASTM-E-208. For the reactor vessel, Charpy tests will be also performed and the results will be used to plot a Charpy transition curve. The NDTT as determined by drop weight test will be used to correlate the Charpy transition curve and establish nonirradiated base points for the surveillance program. See Criterion 32 and Section 5.2.3.5.

The combined static and transient loadings are limited, whenever the reactor coolant system temperature is below NDTT + 60ºF to sufficiently low values to make the probability of a rapidly propagating failure extremely remote.

All the reactor coolant pressure boundary components are constructed in accordance with the applicable codes and comply with the test and inspection requirements of these codes. These test inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding code requirements are performed. The tests and inspection performed on the reactor vessel are summarized in Sections 5.4.5 and 5.4.6.

Excessive embrittlement of the reactor vessel material due to neutron radiation is prevented by providing an annulus of coolant water between the reactor core and the vessel. The peak vessel neutron fluence at 60 ~~32 effective full power~~years ~~(EFPY)~~ at 2700 MWth is calculated to be less than 4.7 ~~3.5~~ x $10^{19}$ n/cm$^2$ (E $\geq$ 1 MeV)~~.~~; ~~T~~the neutron fluence at the limiting vessel material is less than 3.1 ~~1.93~~ x $10^{19}$ n/cm$^2$.

The limiting material is the ~~upper portion of~~ longitudinal weld seam 3-203 at the 15°, 135° and 255° azimuthal locations with a maximum adjusted RT~~NDT~~$_{NDT}$ at 60 years ~~32 EFPY~~ that is below the 10 CFR 50.61 screening limit ~~of 240ºF~~. A surveillance program will be conducted (see Criterion 36) to allow monitoring of the NDT temperature shift of the vessel material during its lifetime. Based on the determined NDT temperature, for a given exposure, operating restrictions to limit vessel stresses would be applied as necessary. The reactor coolant system pressure will not be increased above 500 psia until reactor coolant temperature has been raised to NDTT + 60ºF. Vessel stresses resulting from a pressure of 500 psia are sufficiently low to preclude brittle fracture.

During normal start-up for power operation, the reactor will not be made critical until the reactor coolant system temperature is at least 120ºF greater than the predicted nil ductility transition temperature based on plant records of fast neutron dose to the vessel. The stress criteria include the maximum loads associated with the most severe transients during emergency conditions at operating temperature. ~~The operational restrictions that will be invoked will maintain the minimum temperature above NDTT +120 F for reactor operation.~~ This will assure that a reactivity-induced loading which would contribute to elastic or plastic deformation cannot occur below a reactor operating temperature corresponding to NDTT +120ºF.

The activation of the safety injection systems will introduce highly borated water into the primary system at pressures significantly below operating pressures and will not cause adverse pressure or reactivity effects.

The thermal stresses induced by the injection of cold water into the vessel have been examined. Analysis shows that there is no gross yielding across the vessel wall using the minimum specified yield strength in the ASME Boiler and Pressure Vessel Code, Section III.

Adverse effects that could be caused by exposure of equipment or instrumentation to containment spray water is avoided by designing the equipment or instrumentation to withstand direct spray or by locating it or protecting it to avoid direct spray.

### 3.1.32 CRITERION 32 - INSPECTION OF REACTOR COOLANT PRESSURE BOUNDARY

Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

DISCUSSION

Provisions are made for inspection, testing, and surveillance of the reactor coolant system boundary as described in Section 5.2.5.

The reactor vessel material surveillance program described in Section 5.4.4 conforms with ASTM-E-185-66. Sample pieces taken from the same shell plate material used in fabrication of the reactor vessel are installed between the core and the vessel inside wall. These samples will be removed and tested at intervals during vessel life to provide an indication of the extent of the neutron embrittlement of the vessel wall. Charpy tests will be performed on the samples to develop a Charpy transition curve. By comparison of this curve with the Charpy curve and drop weight tests on specimens taken at the beginning of the vessel life, the change of NDTT will be determined and operating instructions adjusted as required.

fitted with a double gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment vessel and provision is made for testing welds essential to the integrity of containment. Bellows expansion joints are provided on the pipe to compensate for building settlement and differential seismic motion between the reactor building and the fuel handling building.

The bellows expansion joints meet the requirements of ASME Boiler and Pressure Vessel Code, Section III. The fuel transfer tube bellows are designed for a 35 foot head of water. The static head of water is always less than 35 feet.

Bellows design and construction is such that bellows will not deflect more than its designed amount. The bellows is designed to withstand a ~~40~~ 60-year lifetime total of 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion. |

f) Equipment and Personnel Access

Two equipment hatches are provided. These are welded steel assemblies with 28'-0" diameter and 12'-0" diameter clear openings respectively. The 28'-0" diameter hatch cover will be welded back into position upon completion of construction. The design is such that post-weld heat treatment is not required.

The 12'-0" diameter hatch has a double gasketed flanged and bolted cover. Provision is made to pressurize the space between the gaskets to 44 psig.

Two personnel air locks are provided. These are welded steel assembles. Each lock has two double gasketed doors in series. Provision is made to pressurize the space between the gaskets. The doors are mechanically interlocked to ensure that one door cannot be opened until the second door is sealed. Provisions are made for deliberately violating the interlock by the use of special tools and procedures under strict administrative control. Each door is equipped with quick acting valves for equalizing the pressure across the doors. The doors will not be operable unless the pressure is equalized. Pressure equalization is possible from every point at which the associated door can be operated. The valves for the two doors are properly interlocked so that only one valve can be opened at one time, and only when the opposite door is closed and sealed. Each door is designed so that with the other door open, it will withstand and seal against design and testing procedures of the containment vessel. There is visual indication outside each door showing whether the opposite door is open or closed and whether its valve is open or closed. In addition, limit switches are provided to indicate remotely whether doors are open or closed. Control room annunciation is provided for indication of the Personnel Airlock. Status of the Emergency Escape Air Lock is provided on the security display panel. Provision is made outside each door for remotely closing and latching the opposite door so that in the event that one door is accidentally left open it can be closed by remote control. The air-locks have nozzles installed which will permit pressure testing of the lock at any time.

An interior lighting system and a communications system are installed.

3.8-45 Amendment ~~15, (1/97)~~ No. [LATER] |

3.9.1.6 Stress Analysis Results For Repaired Core Support

After repair of the Core Support Barrel and removal of the Thermal Shield in 1983, a stress analysis was performed to verify acceptability of repairs.

The analysis was performed for the region of the core support barrel at the thermal shield lug elevation. The conservative assumption was made that at each of the lug regions the maximum length of lateral crack was circumferential and in the same horizontal plane as the cracks in the other lugs. The point of maximum stress in the region was then established by determining the axis in the plane about which the moment of inertia of the cylindrical section in combination with the load resulted in the maximum stress. The fatigue analysis was performed utilizing the stress concentration factors resulting from the crack arrestor hole size analysis. The design fatigue curves used in the analysis are the more conservative fatigue curves published in the Winter 1982 Addenda to Section III, Appendix I, Figures I-9.2.1 and I-9.2.2.

In addition to the Code Analysis, a confirmatory stress analysis of the core support barrel was performed using sophisticated finite element techniques. Overall effects and local effects of cracks in the core support barrel were evaluated by comparing stress distributions to those of an uncracked barrel. The conclusion of the confirmatory analysis was that the analysis considering the horizontal crack length in the same horizontal plane was conservative.

A summary of the Code Analysis results is shown in Table 3.9-3b.

An evaluation of the cracks in the core support barrel on the basis of fracture mechanics considerations was performed. After discussion with consultants on fracture mechanics it was concluded that insufficient data for the barrel material in a pressurized water reactor environment for service in excess of $10^{11}$ cycles was available. Because of the lack of materials data and the length of cracks in the core support barrel extremely conservative assumptions would have had to be made. The decision was made to use crack arrestor holes sized to reduce stress concentrations to magnitudes compatible with the ASME code fatigue limitations.

The stress concentration factors for a crack with a crack arrestor hole at each end were calculated using available theoretical solutions of stress distributions in plates with openings. (23) The adequacy of the solutions was verified through comparisons with finite element analyses of typical crack geometries and loading conditions.

The "equivalent ellipse" concept is useful in calculating stress concentration factors for a crack with crack arrestor holes at each end. For an elliptical hole in an infinite plate in tension, the stress concentration factor, $K_t$, is given by:

$$K_t = 1 + \cancel{6}\ \underline{\underline{2}}\sqrt{\frac{b}{2r}}$$

<u>Where: b = major length of elliptical hole</u>
<u>r = minimum radius of elliptical hole</u>

3.9-16a Amendment No. ~~16, (1/98)~~ [LATER]

## 3.9.2 ASME CODE CLASS II AND III COMPONENTS

### 3.9.2.1 Design Conditions

The design pressure, temperature and other conditions that were considered in the design of each system containing Code Class 2 or 3 mechanical components are listed in Table 3.9-4.

### 3.9.2.2 Design Loading Combinations

The design loading combinations considered in the component design are: normal (operating design) pressure, temperature and thrust loads combined with seismic, hurricane or tornado loads. Seismic loads and hurricane and tornado loads are not assumed to act concurrently. The design loaning conditions are categorized as design, normal, upset, emergency, and faulted. The stress limits associated with each of the design loadings categories Code Class 2 or 3 components are given in Table 3.9-3A, and for piping in Table 3.9-3.

Tue forces and moments acting on any component in the piping system are supplied to the manufacturer so that it can be insured that the component will function under the applied loads

Loads resulting from transients appropriate to specified plant operating conditions have been considered and accommodated by design. These conditions have been analyzed in accordance with applicable code requirements as an independent case. The transient operating conditions accounted for in the design of the reactor coolant pressure boundary (NSS vendor's scope) is provided in Section 5.2.1.2. Cyclic loading considerations for equipment outside the NSS vendor's scope is discussed below.

The ASME code does not require cyclic analyses for Class 2 and 3 components. Equipment specifications for pumps specify "maximum" moments and forces at the pump nozzles. These maximum moments and forces envelop operating transient loading conditions appropriate for the component. (See Table 3.9-3A footnote 2). For Class 2 and 3 piping the dynamic conditions resulting from fast valve closure and relief valve operation are analyzed as shown in loading combination 3 of Table 3.9-3. These dynamic conditions envelop the operating transients.

For Class I piping and fitting assemblies, fatigue analysis has been performed to ensure the usage factor is adequate for the ~~40~~ 60-year design life. The applicable transients have been assigned operating condition categories, normal (14), upset (U), test(T), emergency (E), or faulted (F). Cyclic loading combinations considered for Class I piping and assemblies include:

Following the above flow at 40ºF from the low pressure safety injection headers through the safety injection lines to the cold leg nozzles will be maintained at 2000 gpm per line (from low pressure safety injection pumps)until equilibrium is reached. This is a "faulted" operating condition.

d. Safety Injection Return Lines

The safety injection return lines (I-1-SI-118, I-1-SI-120, I-1-SI-123 and I-1-SI-125) are subject to 2000 occurrences of a step change from 130°F and 1100 psia to 120°F and 200 psia. This transient occurs upon opening the return line pneumatic valves to relieve the pressure accumulated between the safety injection check valves (V-3113, V-3114 and V-3217 typical). The flow rate varies from 0 to 40 gpm during those step changes. This transient occurs periodically during the operation of the plant.

e. Shutdown Cooling Suction Lines

The shutdown cooling suction lines, I-12- RC-147 and 162, I-10-SI-127 and 130, as a normal operating condition, be subject to 500 occurrences of shutdown cooling with a flow of 3000 gpm, an initial temperature of 350°F max and pressure and temperature varying as appropriate for cooldown beyond 350 °F.

f. Letdown Line

Five hundred (500) heat-up cycles with a flow of 80 gpm and temperature increasing at 100ºF/hr from 70ºF to 550ºF and pressure increasing from atmospheric to 2250 psia over this period. This condition should be considered as a "normal" operating condition.

Five hundred (500) cooldown cycles of flow at 29 gpm and temperature decreasing from 550ºF to 140ºF at a rate of 100ºF/hr and pressure decreasing from 2250 psia to atmospheric. This condition should be considered as a "normal' operating condition. ~~Following transients experienced by the reactor coolant pipe:~~

| Operating Condition Category | | Plant Conditions | Occurrences |
|---|---|---|---|
| N | a – | Heatup, 100ºF/hr | 500 |
| N | b – | Cooldown, 100ºF/hr | 500 |
| N | c – | Loading, 5%/min. | 15,000 |
| N | d – | Unloading, 5%/min. | 15,000 |
| N | e – | Step Load Increase, ~~±10%~~ +10% | 2,000 |
| N | f – | Step Load Decrease, ~~±10%~~ -10% | 2,000 |
| U | g – | Reactor Trip | 400 |
| U | h – | Loss of Reactor Coolant System Flow | 40 |
| U | i – | Loss of Turbine-Generator Load | 40 |
| E | j – | Loss of Secondary Pressure | 5 |
| N | k – | Purification | 1,000 |
| N | l – | Low Volume Control & Makeup | 2,000 |
| N | m – | Boric Acid Dilution | 8,000 |
| U | n – | Loss of Charging Flow | 200 |
| U | o – | Loss of Letdown | 50 |
| U | p – | Regenerative Hx Isolation Long-term | ~~80~~ 150 |
| U | q – | Regenerative Hx Isolation Short-term | 40 |

3.9-22 Amendment No. ~~18, (04/01)~~ [LATER] results on one or more of the following tests: radiographic, liquid penetrant, magnetic particle, ultrasonic or hydrostatic. The seismic analysis or testing described in Section 3.9.1.2 provided by the manufacturer also serves to demonstrate compliance with the applicable sections of the codes.

3.9.2.8 Operational Cycles

The auxiliary feedwater pumps may be subjected to the following number of operational cycles during the plant life: testing ~~480~~ 720 cycles in which the pumps run for 15 minutes during each test; plant cooldown, 500 cycles; and hot standby, 15,000 cycles. In all cases the electrically driven pumps are preferred for operation with the steam turbine driven pump on standby. However, the steam turbine driven pump may be subjected to 300 cycles of the complete system blacking out including the loss of the standby diesel generators. During the performance of the operation the motor operated valves on the discharge are kept closed and the pumps operated on the minimum recirc flow.

Both the electrically driven and the steam turbine driven pumps are capable of withstanding without any damage instantaneous loss of suction should this occur inadvertently.

The component coolant pumps are run continuously while the plant is in operation and may be subjected to 500 shutdown cooling cycles. One of the three component cooling pumps will be on standby at all times. Standby condition will be alternately shared among the three pumps.

The containment spray pumps are ~~will be~~ tested every refueling outage~~year~~ and thus will undergo approximately 40 lifetime full-flow testing cycles.

Table 3.9-3A (con't.)

(5) Loading conditions, i.e., Seismic, Tornado or Hurricane (as appropriate) plus normal operating loadings are considered. Allowables employed by the component manufacturer for support materials varied from 1.33 normal allowable stresses to yield stresses as listed in ASME or AISC codes.

~~TABLE 3.9-3b~~

~~Normal Operation Plus Upset Conditions~~

| ~~Stress Category~~ | ~~Calculated Stress*~~ ~~psi~~ | ~~Allowable Stress~~ ~~Psi~~ |
|---|---|---|
| ~~$P_m$~~ | ~~5,500~~ | ~~16,200~~ |
| ~~$P_m + P_b$~~ | ~~7,300~~ | ~~24,300~~ |
| ~~$P_m + P^h + Q$~~ | ~~21,000~~ | ~~48,600~~ |
| ~~Fatigue Usage Factor < 1~~ | | |

~~*Includes Seismic~~

~~Faulted Condition~~

| ~~Stress Category~~ | ~~Calculated Stress~~ ~~psi~~ | ~~Allowable Stress~~ ~~Psi~~ |
|---|---|---|
| ~~$P_m$~~ | ~~21,200~~ | ~~38,900~~ |
| ~~$P_m + P_b$~~ | ~~42,500~~ | ~~50,000~~ |

Note - Table 3.9-3b is revised and moved to new UFSAR page 3.9-48a.

TABLE 3.9-3B

CORE SUPPORT BARREL MIDDLE CYLINDER CODE ANALYSIS RESULTS

Normal Operation Plus Upset Conditions

| Stress Category | Calculated Stress* psi | Allowable Stress psi |
|---|---|---|
| $P_m$ | 6,100 | 16,100 |
| $P_m + P_b$ | 8,100 | 20,700 |
| $P_m + P_b + Q$ | 23,200 | 48,300 |
| Fatigue Usage Factor < 1 | | |

*Includes Normal Operating Pressure plus OBE

Faulted Condition

| Stress Category | Calculated Stress** psi | Allowable Stress psi |
|---|---|---|
| $P_m$ | 8,500 | 38,600 |
| $P_m + P_b$ | 43,800 | 49,700 |

** Includes SSE plus LOCA

$P_m$ = Membrane Stress

$P_b$ = Bending Stress

Q = Secondary Stress

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Near the bottom of the extension shaft is a larger diameter section which allows the upper guide structure to pick up the extension shafts as the upper guide structure is removed from the reactor vessel.

The drive shaft is a long tube made of 304 stainless steel. It is threaded and pinned to the extension shaft. The drive shaft has circumferential notches along the shaft to provide the means of engagement to the control element drive mechanism.

The magnet assembly consists of a housing, magnet and plug. Two, 2-inch cylindrical Alnico-V magnets with a minimum flux density of 325 gauss are used in the assembly. This magnet assembly is used to actuate the reed switch position indication. The magnets are contained in a housing which is plugged at the bottom. The housing provides a means of attaching the lifting tool for disengaging the CEA from the extension shaft.

In order to engage or disengage a CEA to or from the extension shaft, a special gripper operating tool is attached to the top of the extension shaft assembly when the reactor vessel head has been removed. One part of the tool is attached to the extension sleeve to hold this portion of the extension shaft assembly fixed. Another part of the tool is attached to the operating rod at the magnet assembly and is used to raise the operating rod to conform to the pattern of the slot in the extension sleeve. Withdrawing of the operating rod raises the plunger which in turn allows the fingers of the collet type gripper to collapse to a smaller diameter and allows separation of the extension shaft assembly from the CEA.

4.2.3.1.3 Design Evaluation

(a) Prototype Tests

A prototype magnetic jack type standard CEDM was subjected to accelerated life tests accumulating 100,000 feet of travel equivalent to a ~~40~~ <u>60</u>-year lifetime.

The first phase of the accelerated life test consisted of continuous operation of the mechanism at 40 in/min over a 137 inch stroke lifting and lowering 230 pounds for a total travel of 32,500 feet. This test was performed at simulated normal reactor operating conditions of 600ºF and 2200 psig. Upon completion of the test, the motor bearing surfaces were inspected and measured. A maximum bearing wear of .003-inch was measured. This degree of wear is considered acceptable based on the ~~40~~ <u>60</u>-year design life.

4.3.2.9 Vessel Irradiation

The design of the reactor internals and of the water annulus between the active core and vessel wall is such that the peak vessel neutron fluence at 60 ~~32 effective full power~~ years ~~(EFPY)~~ at 2700 MWth is calculated to be less than 4.7 ~~3.7~~ x $10^{19}$ n/$cm^2$ (E > 1 MeV). The neutron fluence at the limiting vessel material at 60 years ~~32 EFPY~~ is less than 3.1 ~~2.77~~ x $10^{19}$ n/$cm^2$.

The limiting material is the ~~upper portion of~~ longitudinal weld seam 3-203 at the ~~15~~ 15°, 135° and 255° azimuthal locations with a maximum adjusted $RT_{NDT}$ at 60 years ~~32 EFPY~~ that is below the 10 CFR 50.61 screening limit ~~of 240°F~~.

4.3.2.10 References for Section 4.3.2

1 XN-75-27(A), Supplement 1, September 1976.

2 XN-75-27(A), Supplement 2, December 1977.

3 XN-75-27(A), Supplement 3, November 1980.

4 XN-NF-84-12, "St Lucie Unit 1 Cycle 6 Safety Analysis Report Reload Batches XN-1 and XN-IA", Exxon Nuclear Company, February 1984.

5 XN-CC-28, Revision 5, "XTG - A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing", Exxon Nuclear Company, July 1979.

6 XN-75-27(A), "Exxon Nuclear Neutronics Design Methods for Pressurized Water Reactors", Exxon Nuclear Company, June 1975.

7 XN-75-27(A), Supplement 4, December 1985

8 WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," June 1988 (Westinghouse Proprietary)

4.3.3 COMBUSTION ENGINEERING ANALYTICAL METHODS (CYCLES 1-5)

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis

The nuclear design analysis for low enrichment PWR cores is based on a combination of multigroup neutron spectrum calculations, which provide cross sections appropriately averaged over a few broad energy groups, and few-group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. The multigroup calculations include spatial effects in those portions of the neutron energy spectrum where volume homogenization is inappropriate, e.g., the thermal neutron energy range. Most of the calculations are performed with the aid of computer programs embodying analytical procedures and fundamental nuclear data consistent with the current state of the art.

A summary of the analytical tools employed is given below. Comparisons between calculated and measured data which validate the design procedures are presented in Section 4.3.3.1.2. As improvements in analytical procedures are developed and improved nuclear data become available, they will be added to the design procedures, but only after validation by comparison with related experimental data.

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5.2.1.1 Functional Performance Requirements

The function of the reactor coolant system is to remove heat from the reactor core and transfer it to the secondary system by the forced circulation of pressurized borated water. The borated water serves both as a coolant and neutron moderator. The reactor coolant system is designed for the normal operation of transferring 2710 Mwt from the reactor core (2700 Mwt) and reactor coolant pumps (10 Mwt) to the steam generators.

The reactor coolant system also serves as a pressure boundary having a high degree of leak tightness. The integrity of this pressure boundary is assured by appropriate recognition of operating, seismic and/or accident stress loadings. The normal operating pressure of the reactor coolant system is approximately 2235 psig.

The system design temperature and pressure are conservatively established and exceed the combined normal operating value and those resulting from anticipated transients. The effects of instrument error and the response characteristics of the control system are included in the design rating of the systems. The change due to the anticipated transients also considers the effect of reactor core thermal lag, coolant transport time, system pressure drop and the characteristics of the safety and relief valves.

Test pressures for the system and individual components are in accordance with the codes given in Table 5.2-1. The ASME Code specifies that the hydrostatic test pressure shall be 125 percent of design pressure. The allowable number of such tests are limited to those allowed by usage factor analyses.

~~The reactor coolant system is designed for an operating life of 40 years.~~

5.2.1.2 Transients Used in Design and Fatigue Analyses

The following design cyclic transients, which include conservative estimates of the operational requirements for the components, were used in the fatigue analyses required by the applicable codes listed in Table 5.2-1. (Note: Differences exist between the cycles and transients assumed in the design of Unit 1 and those assumed in the design of Unit 2. Further, there may also be unit differences with respect to those cycles and transients required by plant procedure to be tracked). The evaluation for a 60-year plant design life concludes the design cycles listed below, which were based on a 40-year design life, envelope the 60-year plant design life. See Section 18.3.2.1.

a) 500 heatup and cooldown cycles during the design life of the components in the system with heating and cooling at a rate of 100ºF/hr. between 70ºF and 532ºF (653ºF for the pressurizer). This is based on a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred. The heatup and cooldown rate of the system is administratively limited to a value that will assure that these limits will not be exceeded.

b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000.

TABLE 5.4-3

CAPSULE REMOVAL SCHEDULE(5)

| Location on Vessel Wall | Approximate Removal ~~Time~~ Schedule (EFPY) | Predicted Fluence $n/cm^2$ | Lead Factor (3) |
|---|---|---|---|
| 97° (1) | 4.67 | ~~5.5~~ 6.27 x $10^{18}$ | ------ |
| 104° (1) | 9.515 | ~~7.16~~ 9.09 x $10^{18}$ | ------ |
| 284° (1) | 17.23 | 1.41 x $10^{19}$ | ------ |
| 263° | ~~21~~ 38 | ~~2.78~~ 4.40 x $10^{19}$ | 1.37 |
| 83° (2) (4) | ≥38 / Standby | ~~4.24 x $10^{19}$~~ ------ | 1.37 |
| 277°(~~2~~ 4) | Standby | ------ | 1.37 |

(1) Numbers for these capsules are actual.

(2) Fifth capsule is not required to be tested per ASTM E185. It is reserved as standby should an additional license period be considered.

(3) Lead Factor is defined as the capsule fluence/RV base metal peak fluence.

(~~2~~ 4) The capsule removal times were switched for the 83° and 277° capsules. The capsule at 277° was found to be missing its ACME threaded top during a 1996 vessel inspection (Condition Report 96-1064). Without the top, a special removal tool will be required to retrieve the 277° capsule. Both capsules contain identical samples and receive similar fluence since they are 180° apart.

(5) Capsule removal schedule changes require NRC approval per 10 CFR 50, Appendix H.

## 5.5.5 REACTOR COOLANT PUMPS

### 5.5.5.1 Design Bases

The reactor coolant pumps which circulate the reactor coolant through the reactor coolant system are designed to:

a) Circulate reactor coolant with the chemistry identified in Table 9.3-8 at the flows listed in Table 5.5-9 ~~for a design life of 40 years~~.

b) Meet the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class A. Winter 1967 Addenda.

c) Meet the transient operating condition categories listed in Section 5.2.1.2.

d) Provide sufficient moment of inertia to reduce the flow decay through the core upon loss of pump power.

e) Prevent reverse rotation of the pump upon loss of pump power with the other pumps operating.

f) Operate without cooling water for periods up to 10 minutes without incurring seal damage.

Reactor coolant pump parameters and design requirements are listed in Table 5.5-9.

### 5.5.5.2 Description

The reactor coolant is circulated by four vertical, single bottom suction, horizontal discharge, centrifugal motor driven pumps as shown in Figure 5.5-6. The design parameters for the pumps are given in Table 5.5-9.

The reactor coolant pump assembly consists of the pump case, rotating assembly containing the impeller which is keyed and locked to the shaft, pump case cover, motor adapter and motor. The motor is connected to and supported by the pump case through the motor mount adapter. There are two openings on opposite sides of the motor mounts that provide access for assembly of the flanged rigid coupling between the motor and pump and for seal cartridge replacement.



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All portions of the spray systems which are designed to recirculate radioactive water collected in the containment sump are designed to operate in the radiation environment associated with normal plant operation plus the maximum hypothetical accident (MHA). ~~System components such as valve operators, valve packing and pump motors and seals have been specified to operate through an integrated radiation dose of 5 x 10^4 Rad (based on 40 years operation plus MA~~).

Normal operating conditions allow the containment fan coolers to function in a relatively low pressure/low temperature (approximately 0 psig/ 120ºF) atmosphere with a 40 percent relative humidity and average radiation dose of 1 rad/hr.

Upon occurrence of a LOCA, the service environment is altered such that: (1) temperature increases from 120ºF to a maximum, (2) pressure increases from 0 psig to a maximum, (3) humidity increases to 100 percent, and (4) the radiation dose increases to approximately 2 x $10^6$ rad/hr. Also the fan coolers are subjected to a 1720 ppm borated spray. The fan coolers are designed to operate in the post-accident environment for at least one year. Discussion of the environmental qualifications of the fan motors is given in Section 3.11.

Fan and motor bearings are lubricated with a high temperature lubricant suitable for an integrated radiation exposure of 5 x $10^8$ rad. Lubrication is adequate for fan and motor operation for a period of one year under post-MHA conditions. These bearings will be inspected and re-lubricated in accordance with the site preventative maintenance program on a refueling outage basis.

6.2.2.3.4 Natural Phenomena

All components of the containment heat removal system which are necessary to support the system safety functions have been designed as seismic Class I and are installed in seismic Class I structures. Seismic Class I has been specified in purchase specifications, and vendors have substantiated either through test, calculational and/or operational data that system components will remain operable under the design basis earthquake loads.

Refer to Sections 3.7.3 and 3.9 for seismic analysis of system piping and seismic qualification of components, respectively.

6.2.2.4 Testing and Inspection

6.2.2.4.1 Containment Spray System

Performance tests are conducted in the shop to establish pump characteristics. Transient tests are conducted at the pump design point to establish pump ability to withstand a temperature transient of 40ºF to 250ºF in 10 seconds, conservatively simulating the switchover from refueling water tank suction to containment sump suction. Net positive suction head (NPSH) requirements for the pump capacity range are verified by a suction pressure suppression test for each pump.

6.2-55 Amendment No. ~~17 (10/99)~~ [LATER]

Operating procedure restrictions and design features are provided so that the normal safety injection system lineup is not altered except under reduced reactor coolant system pressure conditions. Valve interlocks on the suction line to the low pressure safety injection pumps preclude initiation of shutdown cooling until pressurizer pressure is below 267 psia. System alignment will not be altered until this low pressure condition is reached. Since several hours must elapse after reactor shutdown before this condition is reached, the required level of core cooling is significantly reduced. Therefore, in the event of a pipe break with the system in the shutdown cooling mode, sufficient time exists for operator action to safely control the accident.

This shutdown procedure will occur at most a few times per year. For each shutdown, there is a period of about 25 hours during which automatic initiation of the ECCS is not available, the time required to reduce temperature to the refueling temperature.

6.3.3.3 Service Environment

All safety injection, system components and associated electrical equipment have been examined with regard to capability to withstand post-accident environmental conditions. The design of each component has been determined that the design criteria encompass the most severe condition the equipment will encounter.

Components such as remotely operated valves, and instrumentation and control equipment located within the containment required for initiation of safety injection system operation are designed to withstand the post-accident containment conditions of temperature, pressure, humidity, chemistry and radiation for the time period required.

All other safety injection components required to maintain a functional status have been located outside containment to eliminate exposure of this equipment to the post-LOCA containment conditions. The equipment outside containment (i.e., reference to Figure 6.3-2 indicates location of equipment inside or outside of containment) is designed in consideration of the chemical and radiation effects associated post-LOCA operation.

~~The design life of the safety injection pumps is 40 years, corresponding to the life of the plant.~~ Design pressures and temperatures are in excess of the maximum pressures and temperatures seen during normal operating or accident conditions. Materials of construction for the pumps are compatible with the expected water chemistry under LOCA conditions. A radiation resistance requirement ($10^7$ rads) has also been placed on the pumps, which is in excess of the calculated dose based on plant operation of ~~40~~ 60 years plus a LOCA ~~at the end of the 40 years~~. All power operated valves in the safety injection system which might require operation in the post-LOCA period are located outside containment and are designed in consideration of the attendant spray and radiation environment.

Section 3.11 contains additional discussion concerning the environmental design of mechanical and electrical equipment.

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apply an equivalent maximum horizontal force on the crane calculated to be about 2 1/2 percent of the lifted load, which is less than the original design impact of 10 percent lateral and longitudinal.

The above summarizes how uncontrolled cask descent and potential anomalies were accommodated in the design. The crane is well suited for its intended service, and cask drops from the elevation of the "L" shaped entrance into the spent fuel pool, although conceivable, are unlikely. This notwithstanding, cask drops from this elevation and in various orientations were postulated, and scoping analyses of cask impact for the ten element (about 105 ton) and single element (about 25 ton) casks were conducted. These studies indicate that for the ten element cask sufficient cask energy could be obtained to void the leak tight integrity of the structure thereby causing loss of coolant. Fuel pool integrity is maintained for the single element cask drop. in view of this, Technical Specification limitations imposed ensure that the maximum load which may be handled by the cask crane is a loaded single element cask (about 25 tons).

Use of single element fuel cask results in increasing the crane design factors as follows:

| COMPONENT | D.F. | CONDITION |
|---|---|---|
| Rope (Main Hoist) | 29 | Breaking Strength |
| Pins. Axles, etc. | 21 | Yield Strength |
| Machinery | 21 | Ultimate Strength |
| Rope (Aux Hoist) | 25 | Breaking Strength |
| Structural Steel | 8.4 | Yield Strength |
| Hook | 12.6 | Yield Strength |
| Hook | 21 | Ultimate Strength |

The above design factors will limit the working stresses to a small fraction of the stress ~~valv~~ues associated with component failure. The crane is designed for a minimum of 20,000 fuel load cycles. Reducing the allowable load to a single element cask increases the number of fuel load cycles to <u>in excess of 200,000, which is well beyond the anticipated lifetime loading of the crane.</u>

~~in excess of 200,000. The crane would be subjected to about 6400 full load cycles over the 40 year lifetime.~~

The Staff requires that a cask drop be postulated. In order to comply with this position an analysis has been made of the structural and radiological consequences associated with a 25 ton cask drop from the maximum height of 58 feet above the fuel pool floor.

The cask used in the analysis has a maximum weight when loaded of 25 tons, a base diameter of 33 inches and a height of 195 inches. The physical dimensions of the spent fuel pool are shown in Figures 1.2-18 and 1.2-19.

The cask drop is postulated to occur during normal operating conditions, i.e., the forces acting at the time of the drop include the dead weight of concrete, dead weight of steel, equipment, the weight of water in the pool to elevation +60 ft, and the thermal stresses in the concrete resulting from a water temperature of 150ºF. Ultimate strength design is used with a load factor of 1.0 as outlined in Section 3.8.1.5. Seismic loads in combination with the cask drop load is not a design basis load combination for this facility. The occurrence of an earthquake during the time when the cask is suspended over the pool is very unlikely, about two to three orders of magnitude less than the probability of the seismic occurrence. Accordingly the seismic plus cask drop loading combination was obviated by the acceptably low probability associated with this postulated event.

A number of cask free fall trajectories were analyzed to determine if the leaktight barrier of the pool could be breached and to determine the extent ~~)~~of possible damage to stored fuel. The vertical drop has been determined to be the critical loading condition since it results in the maximum energy at impact. The critical target area for this drop is the cask storage area since the thickness of concrete there is 6 ft compared to 9.5 ft for the rest of the pool. A cask dropping in the tipped position was also considered. It will impact on the cask pit area and the main mat area, thus distributing its total energy between two areas. In addition, the impactive load for the tipped drop is less than that for the vertical drop. Therefore with regard to pool integrity, the tipped drop is not limiting.

The maximum velocity at impact for the vertical drop is determined to be 55 fps assuming a free fall through air from the point of maximum lift to elevation 60' as shown on Figure 9.1-19 with the remainder of the descent through water. The velocity of the cask in water is determined using the equation of motion by Riccato (Reference 1).

$$v^2 = A\text{-}Be^{-cx}$$

where:

$$A = \frac{W\text{-}Fb}{K}$$

$B = A\text{-}Vo^2$, Vo = initial velocity at x = 0

C = 2gk/W

at or near the surface, which are the appropriate consideration for this piping. Experience indicates that large flaws, if present, would be detected during hydrostatic testing, i.e., the hydro provides a satisfactory system integrity check. Based on a considerable experience base with thin walled carbon steel pipe, it is concluded that (i) the use of qualified weldors, (ii) industry approved welding procedures, (iii) visual inspection procedures,and (iv) hydrostatic testing results in piping integrity of an acceptable confidence level. The benefit afforded by the Article ND-5220 NDE requirement is simply that derived from the elimination of small surface flaws in weld areas.

Small surface or internal flaws are local discontinuities that produce local discontinuity type stresses. The relevant consideration is whether or not these flaws can grow in service to a point where the integrity of the piping could be compromised. Defects or notches of one type of another are nearly always present in carbon steel parts because of design requirements, manufacturing and installation methods, or surface conditions. The presence of these local discontinuities may appreciably affect the fatigue properties of the carbon steel piping.

Figure F-106(a) of USA Standard B31.7, Nuclear Power Piping (1969) provides this Code's allowable fatigue curve for carbon and alloy steels with metal temperatures not exceeding 700ºF. The fatigue properties of carbon steel are such that if the alternating stress intensity (Sa) is less than 10,000 psi, fatigue failure of the pipe is not a concern, i.e., the stresses in the pipe do not exceed the endurance limit of the material --- a crack will not be initiated.

The CCW piping may cycle from a low pressure (static head from the component cooling surge tank) and ambient temperature when "N" loop sections are secured, to the maximum operating conditions of 100 psig and 120ºF. The system will see a modest number of such cycles during the plants' lifetime. For an 8 inch schedule 40 pipe the cyclic variation in hoop stress is from 0 to about 1,300 psi. (Since the piping is not subjected to rapid temperature transients, thermal stresses are negligible.) Accordingly, the alternating stress intensity (Sa) is very low, less than 1000 psi. Since Sa is more than an order of magnitude below the values where fatigue becomes a relevant consideration, it is concluded that flaws will not grow, i.e., their presence does not imperil CCW pipe integrity.

Appendix A to ASME Section XI (1974) provides a method to be utilized for the evaluation of flaws detected in metals during inservice inspection. This methodology is normally applied to thick sections where there is a likelihood of flaws and the presence of flaws may be a weighty consideration. This notwithstanding, the methods have been applied to the CCW piping as an alternate means of demonstrating the acceptability of the presence of flaws in the CCW piping. A hypothetical flaw through the pipe wall was postulated. Flaw parameters were selected to maximize the stress intensity factor ($K_I$). Even for this extreme case (piping would not pass the hydro), the low applied stresses in the CCW piping results in a low stress intensity factor range - (ΔKI). The stress intensity factor range is so low that it falls off of Section XI figure A-4300-1. This indicates that the crack growth rate is extemely small --- less than $10^{-8}$ inches/cycle. If the CCW system were removed from service, depressurized and returned to service for over 14,000 cycles ~~daily for 40 years~~ (the system might see one or two such cycles a year),the flaw would grow less than 0.00014 inches. This flaw growth is negligible.

TABLE 9.3-9

DESIGN TRANSIENTS
Regenerative and Letdown Heat Exchangers

| Transient | Cycles in ~~40~~60 Years | Variation Level Initial - Final | Rate | Letdown Flow Initial - Final (GPM) | Charging Flow (GPM) |
|---|---|---|---|---|---|
| Step Power Change | 2000 | 90% - 100% | | 40 - 89 (100 sec)<br>89 - 40<br>in 11.7 min | 44 |
| Step Power Change | 2000 | 100% - 90% | | 40 - 29;<br>29 - 40 | 44<br>(88 2.8 min) |
| Ramp Power Change | 15000 | 15% - 100% | 5%/min | 40 - 128<br>in 16 min<br>128 - 40<br>in 17 min | 44 |
| Ramp Power Change | 15000 | 100% - 15% | -5%/min | 40 - 29;<br>29 - 40<br>in 27 min | 44-88-132;<br>132-88-44<br>in 19 min |
| Reactor Trip | 440 | 100% - 0% | | 40 - 29;<br>29 - 40<br>in 30 min | 44-88-132;<br>132-88-44<br>in 22 min |
| Loss of Load | 45 | 100% - 0% | | 40 - 116-29;<br>29 - 40<br>in 28.3 min | 44-88-132;<br>132-88-44<br>in 20 min |

TABLE 9.3-9 (Cont'd)

| Transient | Cycles in ~~40~~60 Years | Variation Level Initial - Final | Rate | Letdown Flow Initial - Final (GPM) | Charging Flow (GPM) |
|---|---|---|---|---|---|
| Maximum Purification | 1000 | - | | 40-128;<br>128-40 | 44-88-132;<br>132-88-44 |
| Loss of Charging | 100 | - | | 40 - 0<br>0 - 40 | 44-0<br>0-44 |
| Loss of Letdown | 50 | - | | 40 - 0<br>0-128-40<br>15 min after restart | 44 |
| Short Term Isolation - Regen. Ht. Exch. | 400 | - | | 40 - 0<br>0 - 40 | 44-0<br>0-44 |
| Long Term Isolation - Regen. Ht. Exch. | 800 | | | 40 - 0<br>0 - 40 | 44-0<br>0-44 |
| Boron Dilution | 10,000 | - | | 40 - 128<br>128-40 | 44-132<br>132-44 |

9.3-67 Amendment No. ~~18, (04/01)~~[LATER]

# ST. LUCIE UNIT 1 UFSAR

# CHAPTER 18.0
# [NEW]

# 18.0 AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSES ACTIVITIES

The integrated plant assessment for license renewal identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This chapter describes these programs and their planned implementation.

This chapter also discusses the evaluation results for each of the plant-specific time-limited aging analyses performed for license renewal. The evaluations have demonstrated that: the analyses remain valid for the period of extended operation; the analyses have been projected to the end of the period of extended operation; or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

No 10 CFR 50.12 exemptions involving a time-limited aging analysis as defined in 10 CFR 54.3 were identified for St. Lucie Unit 1.

## 18.1 NEW PROGRAMS

### 18.1.1 CONDENSATE STORAGE TANK CROSS-CONNECT BURIED PIPING INSPECTION

A one-time visual inspection will be performed to determine the extent of the loss of material due to pitting and microbiologically influenced corrosion on the external surfaces of the buried piping that connects the St. Lucie Unit 1 and Unit 2 condensate storage tanks. The results of this inspection will be evaluated to determine the need for additional inspections. The inspection will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

### 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 in select systems will be performed and evaluated to establish if the corrosion mechanism is active. 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.

### 18.1.3 PIPE WALL THINNING INSPECTION PROGRAM

The Pipe Wall Thinning Inspection Program manages the aging effect of localized loss of material due to erosion of the internal surfaces of stainless steel Auxiliary Feedwater System piping downstream of the recirculation orifices. Examinations will be performed using volumetric techniques such as ultrasonic testing or radiography. This program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

### 18.1.4 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

The Reactor Vessel Internals Inspection Program manages the aging effects of irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness, loss of mechanical closure integrity of bolted joints, and dimensional changes due to void swelling. The program consists of one-time VT-1 visual examinations and, in some cases, enhanced VT-1 examinations of selected reactor vessel internals parts to be performed early during the period of extended operation. These inspections will be performed in addition to and in conjunction with the examinations required by the St. Lucie ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The examinations will be focused on areas of potential aging effects based on the highest projected combination of stress and fluence. For cast austenitic stainless steel (CASS) parts, analytical methods will be used to identify reactor vessel internals parts that are susceptible to loss of fracture toughness due to thermal embrittlement.

FPL will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial operating license term for St. Lucie Unit 1. This report will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks and acceptance criteria.

### 18.1.5 SMALL BORE CLASS 1 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 the NRC with a report describing the inspection plan prior to its implementation. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 1.

### 18.1.6 THERMAL AGING EMBRITTLEMENT OF CASS PROGRAM

The St. Lucie Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will include a determination of the susceptibility of Class 1 CASS piping components to thermal aging embrittlement and will provide for the subsequent aging management of those components that have been identified as being potentially susceptible. Aging management, if required, will be accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. This program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

# 18.2 EXISTING PROGRAMS

## 18.2.1 ALLOY 600 INSPECTION PROGRAM

This program manages the aging effect of cracking due to primary water stress corrosion for susceptible Alloy 600 components within the Reactor Coolant System (RCS) pressure boundary. This includes the reactor vessel head penetration nozzles, reactor head vent pipe, pressurizer instrument nozzles and heater sleeves, RCS piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray piping fittings, and RCS piping dissimilar metal welds. The program includes examinations of the reactor vessel head penetrations to detect crack initiation consistent with St. Lucie Plant's response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," and ongoing Nuclear Energy Institute (NEI) and Electric Power Research Institute (EPRI) Materials Reliability Project recommendations. Visual examination of external surfaces of susceptible locations during outages, which is included as part of the Boric Acid Wastage Surveillance Program, is also utilized to manage cracking.

## 18.2.2 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

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

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program inspections identify and correct degradation in Class 1, 2, and 3 components and piping. The program manages the aging effects of loss of material, cracking, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. The program provides for inspection and examination of accessible components, including the reactor vessel, reactor vessel internals, steam generators, welds, pump casings, valve bodies, steam generator tubing, and pressure-retaining bolting.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and to require VT-1 inspections of the core stabilizing lugs and core support lugs. This enhancement will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

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

ASME Section XI, Subsection IWE Inservice Inspection Program inspections identify and correct degradation of pressure-retaining components and their integral attachments to the Class MC steel Containment. The program manages the aging effects of loss of material and loss of seal. The program provides for inspection and examination of Containment surfaces, pressure-retaining welds, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure-retaining components in accordance with the requirements of ASME Section XI, Subsection IWE.

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

ASME Section XI, Subsection IWF Inservice Inspection Program inspections identify and correct degradation of ASME Class 1, 2, and 3 component supports. This program manages the aging effect of loss of material. The scope of the program provides for inspection and examination of accessible surface areas of the component supports in accordance with the requirements of ASME Section XI, Subsection IWF.

### 18.2.3 BORAFLEX SURVEILLANCE PROGRAM

The Boraflex Surveillance Program manages the aging effect of change in material properties for the Boraflex material in the spent fuel storage racks.

The program will be enhanced to include areal density testing (in lieu of blackness testing) of the encapsulated Boraflex material in the spent fuel storage racks prior to the end of the initial operating license term for St. Lucie Unit 1.

### 18.2.4 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

The Boric Acid Wastage Surveillance Program manages the aging effects of loss of material and loss of mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. The program addresses the RCS and structures and components containing, or exposed to, borated water. This program utilizes systematic inspections, leakage evaluations, and corrective actions to ensure that boric acid corrosion does not lead to degradation of the pressure boundary or the structural integrity of components, supports, or structures in proximity to borated water systems. This program includes commitments in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

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.

### 18.2.5 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program manages the aging effects of loss of material, cracking, and fouling for primary and secondary systems, closed cooling water, and fuel oil systems, structures, and components. The aging effects are minimized or prevented by controlling the chemical species that cause the underlying mechanism(s) that results in these aging effects. Alternatively, chemical agents, such as corrosion inhibitors and biocides, are introduced to prevent certain aging effects. The program includes sampling activities and analysis. The program provides assurance that elevated levels of contaminants and oxygen do not exist in the systems, structures, and components covered by the program, and thus prevents and minimizes the occurrences of aging effects.

### 18.2.6 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification Program is not credited as an aging management program; however, program evaluations of electrical equipment are identified as time-limited aging analyses.

Equipment covered by the Environmental Qualification Program has been evaluated to determine if the existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment initially qualified for 40 years or less. When analysis cannot justify a qualified life in excess of the license renewal period, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life in accordance with the Environmental Qualification Program.

### 18.2.7 FATIGUE MONITORING PROGRAM

The Fatigue Monitoring Program is considered a confirmatory program to ensure that fatigue time-limited aging analysis assumptions remain valid for the period of extended operation; it is not credited as an aging management program.

The Fatigue Monitoring Program is designed to track design cycles to ensure that RCS components remain within their design fatigue limits. Design cycle limits for St. Lucie Unit 1 are provided in Sections 3.9.2.2, 5.2.1.2, and 5.5.1.1. The specific fatigue analyses validated by the Fatigue Monitoring Program are associated with the reactor vessel, reactor vessel internals, pressurizer, steam generators, reactor coolant pumps, and RCS Class 1 piping. Administrative procedures provide the methodology for logging design cycles. These procedures will be enhanced to provide guidance in the event design cycle limits are approached. This enhancement will be completed prior to the end of the initial operating license term for St. Lucie Unit 1.

### 18.2.8 FIRE PROTECTION PROGRAM

The Fire Protection Program manages the aging effect of loss of material for the components of the Fire Protection System. Additionally, this program manages the aging effect of loss of material for structural components associated with fire protection. Appendix 9.5A contains a detailed discussion of the Fire Protection Program.

### 18.2.9 FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion Program manages the aging effect of loss of material due to flow accelerated corrosion. The Flow Accelerated Corrosion Program predicts, detects, monitors, and mitigates flow accelerated corrosion in high energy carbon steel piping associated with the Main Steam, Reactor Coolant (steam generators), Main Feedwater and Blowdown Systems, and is based on industry guidelines and experience. The program includes analysis and baseline inspections; determination, evaluation, and corrective actions for affected components; and follow-up inspections.

The Flow Accelerated Corrosion Program will be enhanced to address internal and external loss of material of drain lines and selected steam trap lines due to flow accelerated corrosion and external general corrosion. This enhancement will be completed prior to the end of the initial operating license term for St. Lucie Unit 1.

## 18.2.10 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

The Intake Cooling Water System Inspection Program manages the aging effects of loss of material due to various corrosion mechanisms, and particulate and biological fouling for Intake Cooling Water (ICW) System components and the ICW side of the Component Cooling Water heat exchangers. The program includes inspections, performance testing, evaluations, and corrective actions that are performed as a result of FPL commitments in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

## 18.2.11 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of loss of material, cracking, loss of seal, and fouling (mechanical components only) for various plant systems, structures, and components. The scope of the program provides for visual examination of selected surfaces of specific systems, structures, and components. Additionally, the program provides for replacement/"refurbishment of selected components on a specified frequency, as appropriate, and periodic sampling and water removal from fuel oil storage tanks. The frequency of inspections varies depending on the specific component, the aging effect being managed, and plant operating experience.

Specific enhancements to the scope of this program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 1.

## 18.2.12 REACTOR VESSEL INTEGRITY PROGRAM

The Reactor Vessel Integrity Program manages reactor vessel irradiation embrittlement and encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure-Temperature Limit Curves

Program documentation will be enhanced to integrate aspects of the Reactor Vessel Integrity Program prior to the end of the initial operating license term for St. Lucie Unit 1.

### 18.2.12.1 REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION

This subprogram manages the aging effect of reduction in fracture toughness of the reactor vessel materials (beltline plates and welds) due to neutron irradiation embrittlement by performing Charpy V-notch and tensile tests on the reactor vessel irradiated specimens. The Reactor Vessel Surveillance Capsule Removal and Evaluation subprogram is an NRC-approved program that meets the requirements of 10 CFR 50, Appendix H. The surveillance capsule withdrawal schedule is specified in Table 5.4-3.

### 18.2.12.2 FLUENCE AND UNCERTAINTY CALCULATIONS

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline plates and welds.

### 18.2.12.3 MONITORING EFFECTIVE FULL POWER YEARS

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessel to ensure that the pressure-temperature limits and end-of-life reference temperatures are not exceeded.

### 18.2.12.4 PRESSURE-TEMPERATURE LIMIT CURVES

This subprogram provides pressure-temperature limit curves for the reactor vessel to establish the RCS operating limits. The pressure-temperature limit curves are included in the Technical Specifications.

## 18.2.13 STEAM GENERATOR INTEGRITY PROGRAM

The Steam Generator Integrity Program is consistent with the guidelines provided by the Nuclear Energy Institute's NEI 97-06, "Steam Generator Program Guidelines." The program ensures that steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The program manages the aging effects of cracking and loss of material.

## 18.2.14 SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling (for mechanical components only), loss of seal, and change in material properties. The program provides for periodic visual inspection and examination for degradation of accessible surfaces of specific systems, structures, and components, and corrective actions, as required, based on these inspections.

This program will be enhanced to provide guidance for managing the aging effects of inaccessible concrete, inspection of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion. These enhancements will be made prior to the end of the initial operating license term for St. Lucie Unit 1.

# 18.3 TIME-LIMITED AGING ANALYSIS ACTIVITIES

## 18.3.1 REACTOR VESSEL IRRADIATION EMBRITTLEMENT

The St. Lucie Unit 1 reactor vessel is described in Chapters 4 and 5. Time-limited aging analyses (TLAAs) applicable to the reactor vessel are:

- pressurized thermal shock
- upper-shelf energy
- pressure-temperature limits

The Reactor Vessel Integrity Program, described in Section 18.2.12, manages reactor vessel irradiation embrittlement utilizing subprograms to monitor, calculate, and evaluate the time-dependent parameters used in the aging analyses for pressurized thermal shock, Charpy upper-shelf energy, and pressure-temperature limits to ensure continuing vessel integrity through the period of extended operation.

### 18.3.1.1 PRESSURIZED THERMAL SHOCK

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature ($RT_{PTS}$) whenever a significant change occurs in projected values of $RT_{PTS}$, or upon request for a change in the expiration date for the operation of the facility.

The calculated $RT_{PTS}$ values that bound the 60-year period of operation for the St. Lucie Unit 1 reactor vessel are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the reactor vessel during the license renewal period.

The analysis associated with pressurized thermal shock has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 18.3.1.2 UPPER-SHELF ENERGY

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G, requires licensees to submit an analysis at least 3 years prior to the time that the USE of any reactor vessel material is predicted to drop below 50 ft-lbs, as measured by Charpy V-notch specimen testing.

An evaluation was performed to demonstrate continued acceptable margins of safety against fracture through the end of the period of extended operation. All reactor vessel beltline material USE projections remain acceptably above the 10 CFR 50, Appendix G, limit of 50 ft-lbs at the end of the 60-year period of operation using a conservative bounding fluence.

The analysis associated with USE has been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 18.3.1.3 PRESSURE-TEMPERATURE LIMITS

The requirements in 10 CFR 50, Appendix G, stipulate that heatup and cooldown of the reactor pressure vessel be accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within the limits of Appendix G defined by the reactor vessel fluence.

The heatup and cooldown pressure-temperature limits are presented in the Unit 1 Technical Specifications. The pressure-temperature curves will be updated as the operating schedule requires. In addition, low temperature overpressure protection (LTOP) requirements will be updated to ensure that the pressure-temperature limits are not exceeded for postulated plant transients.

The analyses associated with reactor vessel pressure-temperature limits for St. Lucie Unit 1 will be available prior to entering the period of extended operation, in accordance with the requirements of the Reactor Vessel Integrity Program and consistent with 10 CFR 54.21(c)(1)(ii).

## 18.3.2 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time-limited aging analyses for St. Lucie Unit 1. Specific components have been designed considering design cycle assumptions, as listed in vendor specifications and in Sections 3.9.2 and 5.2.1.2.

### 18.3.2.1 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 1 COMPONENTS

The reactor vessel (including control element drive mechanisms), reactor vessel internals, pressurizer, steam generators, and the reactor coolant pumps have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III. The reactor coolant piping was originally designed in accordance with ANSI B 31.7, "Nuclear Power Piping." The pressurizer surge line was reanalyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." These design codes require a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded.

Reactor vessel internals fatigue is addressed in Section 18.3.7.1.

Fatigue usage factors for critical locations in the St. Lucie Unit 1 Nuclear Steam Supply System Class 1 components were determined using design cycles that were specified in the plant design process or as a result of industry fatigue issues (e.g., thermal stratification). These design cycles were intended to be conservative and bounding for all foreseeable plant operational conditions. The design cycles were subsequently utilized in the design stress reports for the Class 1 components satisfying ASME fatigue usage design requirements.

Experience has shown that actual plant operation is often very conservatively represented by these design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the period of extended operation, the design cycles applicable to the Class 1 components were assembled.

The actual frequency of occurrence for the fatigue sensitive design cycles was determined and compared to the design cycle set. The severity of the actual plant cycles was also compared to the severity of the design cycles. These comparisons were performed in order to demonstrate that on an event-by-event basis the design cycle profiles envelope actual plant operation. In addition, a review of the applicable administrative and operating procedures was performed to verify the effectiveness of the Fatigue Monitoring Program. The reviews described above concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the structural integrity of the Class 1 components have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

For license renewal, continuation of the Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. The Fatigue Monitoring Program is considered a confirmatory program.

### 18.3.2.2 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 2 AND 3 AND ANSI B31.1 COMPONENTS

St. Lucie Unit 1 has a number of piping systems within the scope of license renewal that were originally designed to the requirements of ANSI B31.7, Class 2 and 3, or ANSI B31.1, "Power Piping." Subsequently, piping systems originally designed to the requirements of ANSI B31.7, Class 2 and 3, were reconciled to ASME Section III, Class 2 and 3. Piping systems designed to these requirements include a stress range reduction factor to provide conservatism in the design to account for cyclic conditions due to operations. The stress range reduction factor is 1.0 as long as the location does not exceed 7000 full temperature thermal cycles during its operation. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years.

A review of ASME Section III, Class 2 and 3, and ANSI B31.1 piping within the scope of license renewal was undertaken in order to establish the cyclic operating practices of those systems that operate at elevated temperatures. Based on industry guidance, any piping system with operating temperatures less than 220°F (carbon steel) or 270°F (stainless steel) may be conservatively excluded from further consideration of thermal fatigue.

Under current plant operating practices, piping systems within the scope of license renewal are only occasionally subjected to cyclic operation. Typically these systems are subjected to continuous steady-state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or for periodic testing. The review of applicable plant systems determined that, except for the RCS hot-leg sample piping, components will not exceed 7000 equivalent full temperature thermal cycles during the period of extended operation. Therefore, the current piping analyses remain valid for the period of extended operation.

The RCS hot-leg sample lines could exceed the 7000 equivalent full temperature thermal cycles during the period of extended operation based on the current sampling practices. The sample piping and tubing were re-evaluated to consider the projected number of cycles and the analyses were found acceptable for the period of extended operation.

Except for the RCS hot-leg sample lines, the ASME Section III, Class 2 and 3, and ANSI B31.1 piping fatigue analyses within the scope of license renewal remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The RCS hot-leg sample lines' fatigue analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

### 18.3.2.3 ENVIRONMENTALLY ASSISTED FATIGUE

Generic Safety Issue (GSI) 190 was initiated by the NRC staff because of concerns about the potential effects of reactor water environments on RCS component fatigue life during the period of extended operation. The FPL approach to address reactor water environmental effects accomplishes two objectives. First, the TLAA on fatigue design has been resolved by confirming that the original transient design limits remain valid for the 60-year operating period. Confirmation by fatigue monitoring will ensure that these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment.

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995, fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system (NSSS) vendors. The pressurized water reactor (PWR) calculations included in NUREG/CR-6260, especially for the "Older Vintage Combustion Engineering Plant," match St. Lucie relatively closely with respect to design codes used, as well as the analytical approach and techniques used. In addition, the design cycles considered in the evaluation match or bound the St. Lucie Unit 1 design.

Environmental fatigue calculations have been performed for St. Lucie Unit 1 for those component locations included in NUREG/CR-6260 using the appropriate methods contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," March 1998, or NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999, as appropriate. Based on these results, all component locations were determined to be acceptable for the period of extended operation, with the exception of the pressurizer surge line (specifically the surge line elbow below the pressurizer).

FPL has selected aging management to address pressurizer surge line fatigue during the period of extended operation, in lieu of performing additional analyses to refine the fatigue usage factors. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be adequately managed during the extended period of operation by the continued performance of the St. Lucie ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program, as described in Section 18.2.2.1. Additionally, specific requirements will be included to evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue (see Section 18.2.2.1).

### 18.3.3 ENVIRONMENTAL QUALIFICATION

The thermal, radiation, and wear cycle aging analyses of plant electrical and I&C components have been identified as TLAAs for St. Lucie Unit 1. In particular, the environmental qualification evaluations of electrical equipment with a 40-year qualified life or greater have been determined to be TLAAs.

Equipment included in the St. Lucie Environmental Qualification Program has been evaluated to determine if existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment currently qualified at St. Lucie for 40 years or less. When aging analysis cannot justify a qualified life into the license renewal period, then the component or parts will be replaced prior to exceeding their qualified lives in accordance with the Environmental Qualification Program, as described in Section 18.2.6.

Age-related service conditions that are applicable to the environmentally qualified equipment (i.e., 60 years of exposure versus 40 years) were evaluated for the period of extended operation to verify that the current environmental qualification analyses are bounding. The evaluations considered radiation, thermal, and wear cycle aging effects.

Therefore, the analyses associated with the environmental qualification of electrical equipment remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 18.3.4 CONTAINMENT PENETRATION FATIGUE

Containment penetration bellows are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The containment penetrations are categorized as follows:

- Type I — Those which must accommodate considerable thermal movements (hot penetrations)
- Type II — Those which are not required to accommodate thermal movements (cold penetrations)
- Type III — Those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV — Containment sump recirculation suction lines
- Type V — Fuel transfer tube

The containment penetration bellows fatigue analyses have been evaluated and determined to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

## 18.3.5 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A Leak-Before-Break (LBB) analysis was performed for Combustion Engineering designed Nuclear Steam Supply Systems (NSSS), which included St. Lucie Unit 1. The LBB analysis was performed to show that any potential leaks that develop in the RCS primary coolant loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. As documented in a March 5, 1993, NRC letter to FPL, the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie Units are bounded by the Combustion Engineering Owners Group analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie Units.

The aging effects that must be addressed during the period of extended operation include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the RCS loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel (CASS) components. This effect results in a reduction in fracture toughness of the material.

A review concluded that the LBB analysis used conservative material toughness properties relative to correlations developed for fully aged cast stainless steel, which covers the extended period of operation. Therefore, the thermal aging assumptions used for the CASS piping do not satisfy one of the six criteria for a TLAA.

The LBB fatigue crack growth analysis assumes 40-year design cycles. The plant design cycles are consistent with those utilized in the fatigue crack growth analysis and bound the period of extended operation. Fatigue crack growth for the period of extended operation is negligible.

The RCS primary loop piping LBB fatigue crack growth analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

### 18.3.6 CRANE LOAD CYCLE LIMIT

The following cranes have load cycle assumptions that result in the fatigue analyses being TLAAs:

- Reactor Building Polar Crane
- Intake Structure Bridge Crane
- Reactor Containment Building Auxiliary Telescoping Jib Crane

(Note: Fuel handling equipment does not require a TLAA evaluation because its lifting function is not in the scope of license renewal.)

The load cycles for these cranes were evaluated for the period of extended operation. For each crane, the actual usage over the projected life through the period of extended operation will be far less than the analyzed quantity of cycles. All the cranes in the scope of license renewal will continue to perform their intended function throughout the period of extended operation.

Therefore, the analyses associated with crane design, including fatigue, are valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

### 18.3.7 CORE SUPPORT BARREL

During the 1983 refueling outage, the reactor vessel internals core support barrel (CSB) and thermal shield assembly were observed to be damaged. The thermal shield was permanently removed and the CSB was repaired at the thermal shield support lug locations. Four lugs were separated from the CSB and through-wall cracks were adjacent to some damaged lug areas. Through-wall cracks were arrested with crack arrestor holes, non-through-wall cracks were machined out, and lug tear out areas were machined and patched as necessary. The crack arrestor holes were sealed by inserting expandable plugs.

Analysis of the CSB repair method was performed by the NSSS supplier to demonstrate that the repair patches and expandable plug designs were acceptable for the remaining (40-year) life of the plant consistent with ASME code allowable stresses.

The analyses and follow-up inspection reports for the repaired CSB and the expandable plugs were screened against the six TLAA criteria. It was determined that two specific elements of the repair qualify as TLAAs: 1) fatigue analysis of the CSB middle cylinder; and 2) acceptance criteria for the CSB expandable plugs' preload based on irradiation-induced stress relaxation.

#### 18.3.7.1 CORE SUPPORT BARREL FATIGUE ANALYSIS

As discussed in Section 18.3.2.1, the 40-year design cycles bound the extended period of operation. Therefore the CSB fatigue analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

### 18.3.7.2 CORE SUPPORT BARREL REPAIR PLUG ANALYSIS

The repair plugs are of an expandable design that allows the plugs to be preloaded against the CSB. Preload is required to provide proper seating of the plugs and patches and to prevent movement of the plugs due to hydraulic drag loads. The original evaluation of plug design preload verified that the design preload was sufficient to accommodate normal operating hydraulic loads and thermal deflections for the original operating life of the plant.

The original CSB plug preload analysis was revised for increased fluence (60-year period of operation) and irradiation-induced relaxation input. The analysis concluded that all the repair plug flange deflection measurement readings are sufficient to meet the minimum required values and maintain the plugs' preload. The CSB repair plugs will therefore perform their intended function for the period of extended plant operation.

The CSB preload stress relaxation analysis has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 18.3.8 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

Small diameter Alloy 600 nozzles, such as pressurizer and RCS hot-leg instrumentation nozzles in Combustion Engineering designed PWRs, have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking. The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the "half nozzle" weld repair has been used to repair selected Alloy 600 instrument nozzles. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

A half nozzle repair was implemented on a Unit 1 RCS hot-leg instrumentation nozzle in April 2001. In response to NRC questions regarding this repair, FPL documented that the indications in the "J" weld were bounded by the fracture mechanics analysis provided in Combustion Engineering Owner's Group (CEOG) Topical Report CE NPSD-1198-P.

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. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Unit 1 UFSAR. This generic 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.

The flaw growth analysis of the Unit 1 RCS hot-leg Alloy 600 instrument nozzle repair has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

# APPENDIX A2

## UNIT 2 UPDATED FSAR SUPPLEMENT

# INTRODUCTION

This Appendix contains the St. Lucie Unit 2 UFSAR Supplement required by 10 CFR 54.21(d). The St. Lucie LRA contains the technical information required by 10 CFR 54.21(a) and (c). Chapter 3 and Appendix B of the LRA provide descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Chapter 4 of the LRA contains the evaluations of the time-limited aging analyses (TLAAs) for the period of extended operation. These LRA sections have been used to prepare the program and activity descriptions that are contained in the UFSAR Supplement.

This UFSAR Supplement will be incorporated into the St. Lucie Unit 2 UFSAR following issuance of the renewed operating license for St. Lucie Unit 2. Upon inclusion of the UFSAR Supplement in the St. Lucie Unit 2 UFSAR, changes to the descriptions of the programs and activities for their implementation will be made in accordance with 10 CFR 50.59 and St. Lucie Plant's NRC commitment management program.

# ST. LUCIE UNIT 2 UFSAR

# CHAPTER 1 CHANGES

The tubes are fabricated into assemblies in which end fittings prevent axial motion and spacer grids prevent lateral motion of the tubes. Beginning with Region N, the fuel incorporates the GUARDIAN™ fuel assembly design to screen and entrap debris. The GUARDIAN™ design employs a redesigned bottom spacer grid that provides positive axial restraint to the rods and added screening features. Region N also includes the addition of "backup arches" adjacent to all cantilevered springs in the interior of the upper H1D-1L spacer grid. The backup arch limits the possible compression of the grid spring, and thereby better maintains the proper geometry between the grid support features and the fuel rod during fabrication and operation. This same feature was present in peripheral locations in each Zircaloy spacer grid for all previous St. Lucie 2 fuel batches. In these locations, the backup arches protect the grid springs that may be subject to compression during fuel handling, when peripheral fuel rods can be pressed inward as bowed fuel assemblies are slid past one another in the core. In the new upper grid design, the arches will be present at all 440 interior spring locations in the grid. The backup arches will thus limit compression of grid springs in all interior locations during fuel rod loading.The control element assemblies (CEAs) consist of inconel clad boron carbide absorber rods which are guided by zircaloy tubes located within the fuel assembly. The core consists of 217 fuel assemblies with three U-235 enrichments in a three batch, mixed central zone arrangement.

Minimum departure from nucleate boiling ratio (DNBR) during normal operation and anticipated operational occurrences is not less than 1.28 (cycle 1 was 1.19) using the CE-1 correlation. The maximum center line temperature of the fuel, evaluated at the design overpower condition, is below that value which could lead to fuel rod failure. The melting points of the UO2 and $UO_2$-$Gd_2O_3$ and/or $UO_2$-$Er_2O_3$ are not reached during routine operation and anticipated operational occurrences.

The combined response of the fuel temperature coefficient, the moderator temperature coefficient, the moderator void coefficient and the moderator pressure coefficient to an increase in reactor thermal power is a decrease in reactivity. In addition, the reactor power transient remains bounded and damped in response to any expected changes in any operating variable.

Control element assemblies (CEAs) are capable of holding the core sub-critical at hot zero power conditions with margin following a trip even with the most reactive CEA stuck in the fully withdrawn position.

Fuel rod clad is designed to maintain cladding integrity throughout fuel life. Fission gas release within the rods and other factors affecting design life are considered for the maximum expected exposures.

The reactor and control systems are designed so that any xenon transients are adequately damped.

The reactor in conjunction with the Reactor Protective System is designed to accommodate safely and without fuel damage, the anticipated operational occurrences.

The reactor vessel and its closure head are fabricated from manganese molybdenum nickel steel internally clad with austenitic stainless steel. The vessel and its internals are designed so that the integrated neutron flux does not exceed ~~3.2~~ 4.9 x $10^{19}$ n/$cm^2$ (E > 1 Mev) over the ~~40~~ 60-year design life of the vessel.

Power excursions which could result from any credible reactivity addition do not cause damage, either by deformation or rupture of the reactor vessel and do not impair operation of the Engineered Safety Features.

The internal structures include the core support barrel, the lower support structure, the core shroud, the hold-down ring and the upper guide structure assembly. The core support barrel is a right circular cylinder supported from a ring flange from a ledge on the reactor vessel. The flange carries the entire weight of the core. ~~m-e~~The lower support structure transmits the weight of the core to the core support barrel by means of vertical columns and a beam structure. The core shroud surrounds the core and limits the amount of coolant bypass flow. The upper guide structure provides a flow shroud for the CEAs and prevents upward motion of the fuel assemblies during pressure transients. Lateral motion limiters or snubbers are

# ST. LUCIE UNIT 2 UFSAR

# CHAPTER 2 CHANGES

2.5.2.7.1 Earthquake Frequency Analysis

The probability of a seismic event equaling or exceeding the OBE was computed using standard statistical methods. The region surrounding the site was subdivided into areas of similar seismicity (see Subsection 2.5.2.3 and Figure 2.5-32) and the statistical properties of seismic events were developed for each area. The effects of events in neighboring provinces were attenuated to the site. The annual probability of events of each intensity greater than or equal to V MM at the site was computed. Horizontal accelerations for each intensity were taken from the 1975 Trifunac-Brady relationship. The annual probability for an event greater than or equal to .05g was interpolated from the results of this computation, and the probability of occurrence of one or more such events was computed. The results of these computations indicated a probability of occurrence of this event of ~~1.3~~ approximately 2 percent over the ~~40~~ 60-year life of the plant, or about once per 3,000 years.

## 2.5.3 SURFACE FAULTING

### 2.5.3.1 Geologic Conditions of the Site

The geologic conditions of the site and surrounding area have been described in the Subsections 2.5.1.1 and 2.5.1.2. Geologic structure and hypothesized faulting in the region have been discussed in Subsection 2.5.1.1.4. It is concluded that no seismic generative faults exist within 200 miles of the site. Figure 2.5-8 shows the locations of hypothesized faulting within peninsular Florida.

### 2.5.3.2 Evidence or Absence of Fault Offset

No specific detailed reports on the geology and groundwater resources of St Lucie County have been published; however, geologic studies have been reported for Martin County to the south[2] and Indian River[1] and Brevard[39] Counties to the north. Figure 2.5-27 is a map showing all hypothesized structures in the three county area.

2.5.3.2.1 Hypothesized Faulting in Indian River County

Bermes[1] utilized data from wells drilled into Eocene strata to develop geologic sections in Indian River County. These sections indicated Eocene and Miocene strata sloped gently to the southeast in most of the county. Bermes reported an apparent change in dip from less than five ft. per mile to greater than 70 ft. per mile and the occurrence of Oligocene age beds near the eastern margin of the county. He postulates a somewhat complex system of three high-angle, normal faults essentially parallel to the coastline (see Figure 2.5-27) to explain the steepening dip and the occurrence and apparent thickening in Oligocene strata to the east. Strata on the east side of the faults were projected to be downthrown. The faults were postulated based on elevation differences of about 225 ft. in the top of the Ocala group over a horizontal distance of about 2.5 miles. He did not discuss the age of the faulting, but the fault traces shown in his geologic sections terminated at the base of Miocene strata, indicating an age of last movement of at least 20 million years.

# ST. LUCIE UNIT 2 UFSAR

# CHAPTER 3 CHANGES

In case of a rupture of the process pipe in the annulus area, the guard pipe acts to direct the fluid back into the containment vessel, thus preventing overpressurization of the annulus. The penetration is designed to accommodate all forces and moments due to both thermal expansion and pipe rupture.

d) Containment Sump Recirculation Suction Lines

A special type of penetration assembly (Type IV) is provided for the suction lines from the containment sump. These lines are used following a LOCA to allow recirculation of containment sump water by the containment spray and high pressure safety injection pumps.

As shown on Figure 3.8-6, each line consists of a double barrier concentric pipe from the sump up to the suction line isolation valve outside the containment. The penetration assembly is designed for the differential motion associated with the SSE.

e) Fuel Transfer Tube Penetration

A fuel transfer tube penetration (Type V) is provided to transport fuel rods between the refueling transfer canal and the spent fuel pool during refueling operations of the reactor. The penetration is shown on Figure 3.8-7 and consists of a 36 in. diameter stainless steel pipe installed inside a 48 in. pipe. The inner pipe acts as the transfer tube and is fitted with a double gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pool. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment vessel and provision is made for testing welds essential to the integrity of containment. Bellows expansion joints are provided on the pipe to compensate for building settlement and differential seismic motion between the Reactor Building and the Fuel Handling Building.

The bellows expansion joints which form a part of the containment boundary meet the requirements of ASME Code, Section III. The fuel transfer tube bellows are designed for a 35 foot head of water.

Bellows design and construction is such that the bellows does not deflect more than its designed amount: The bellows is designed to withstand a ~~40~~ 60-year lifetime total of 7,000 cycles of expansion and compression due to operating thermal expansion and 200 cycles of differential settlement and seismic motion.

f) Containment Vacuum Breaker Penetration

The penetration consists of a nozzle welded on the containment vessel with a check valve inside the containment and a butterfly valve outside the containment (see Figure 3.8-8).

The containment vessel penetration details are shown on Figures 3.8-9, 3.8-10 and 3.8-11. Shield Building penetration details are shown on Figure 3.8-9.

and safety are involved. Such considerations require compliance with safety criteria as may be specified by jurisdictional authorities.

Test (T) - Test conditions are those tests in addition to the 10 hydrostatic or pneumatic tests permitted by ASME Code, Section III, including leak tests or subsequent hydrostatic tests.

The appropriate loading combination and stress limits for each of the above conditions are discussed in Subsection 3.9.3.1.

In support of the design of each Quality Group A component, a fatigue analysis of the combined effects of mechanical and thermal loads is performed in accordance with the requirements of ASME Code, Section III. The purpose of the analysis is to demonstrate that fatigue failure does not occur when the components are subjected to typical dynamic events which may occur in the power plant.

The fatigue analysis is based upon a series of dynamic events depicted in the respective component specifications. Associated with each dynamic event is a mechanical, thermal-hydraulic transient presentation along with an assumed number of occurrences for the event. The presentation is generally simple and straightforward, since it is meant to envelop the actual plant response. The intent is to present material for purposes of design. A best-estimate representation of the expected plant dynamic response is neither intended nor appropriate. The fundamental concept is to ensure that the consequences of the normal and upset conditions which are expected to occur in the power plant are enveloped by one or more of the dynamic event portrayals in the component specifications. The number of occurrences selected for each dynamic event is considered to be conservative, so that in the aggregate a ~~40~~ 60-year useful life is provided by this design process.

A stress analysis is performed on Quality Group A piping in accordance with the ASME Code, Section III, 1971 edition and all addenda up to and including Summer 1973 addenda. A stress report is developed in accordance with Section NB of ASME Code, Section III. The Quality Group A piping is listed in Table 3.9-1.

The Quality Group A components listed in Table 3.9-1 are analyzed with the appropriate loading combinations of pressure, temperature and flow transients for the normal, upset, emergency, faulted and test conditions. Design load combinations and stress limits for the above components are given in Subsection 3.9.3.

Quality Group A piping is classified as seismic Category I and is analyzed as such. The operating basis earthquake (OBE) loading is considered to occur five times over the plant life with 40 cycles for each event. One safe shutdown earthquake (SSE) event is assumed to occur for Quality Group A piping for the life of the plant.

The ASME Quality Group A valves are designed in accordance with Article NB-3000 of ASME Code, Section III. The Quality Group A valves are as listed in Table 3.9-1. When required by ASME Code, Section III the Quality Group

## 3.9.3 ASME CODE CLASS 1, 2 and 3 COMPONENTS, COMPONENT SUPPORTS AND CORE SUPPORT STRUCTURES

### 3.9.3.1 LOADING COMBINATIONS, DESIGN TRANSIENTS AND STRESS LIMITS

ASME Code Class 1, 2 and 3 system components are designed in accordance with the rules and methods specified in the ASME code. The design stress limits of the ASME Code (including code cases) are selected to insure the pressure retaining integrity of safety class equipment. Code cases utilized by the A/E have been approved by Regulatory Guide 1.84 "Design and Fabrication Code Case Acceptability" (R9) and 1.85 "Material Code Cases utilized by the NSSS Vendor" (R9) is discussed in FSAR Section 5.2.

Design transients for ASME Code Class 1 components are provided in Table 3.9-3, Stress limits for A/E Supplied Class 1 components are described in Subsection 3.9.3,1,1. The stress limits and loading combinations for NSSS Supplied Class 1, 2, and 3 components are described in Subsection 3.9.3.1.3.

ASME Code Class 2 and 3 components are designed for the concurrent loadings produced by pressure, deadweight, temperature distributions, the vibratory motion of the safe shutdown earthquake (SSE), and the dynamic system loadings associated with the appropriate plant faulted condition. The design loading combinations for specific plant operating conditions are listed in Table 3.9-5. Additionally, an investigation was performed for all Safety Class 2 and 3 piping systems (irrespective of operating temperature) to demonstrate that the number of equivalent thermal cycles, as defined in ASME Subsection NC 3611.2, was sufficiently low to confirm the conservatism of the existing stress analyses.

In accordance with the agreement reached at a meeting with the NRC and Florida Power & Light Company on October 14, 1982 an acceptance criteria of 1000 "Realistic" cycles was employed. In conducting this analysis, the following Safety Class 2 and 3 systems were reviewed:

| | |
|---|---|
| Reactor Coolant | Component Cooling Water |
| Charging | Letdown |
| Safety Injection | Auxiliary Feedwater |
| Main Steam | Containment Spray |
| Main Feedwater | Intake Cooling Water |

A sample calculation specifying methodology and a summary of the results is provided in Table 3.9-5b.

Using realistic values of cycle frequencies, all systems were shown to exhibit approximately 700 equivalent cycles. Using all the thermal transients that appear in the Safety Class 1 specification (Refer to Table 3.9-5b), which is conservative both in frequency and temperature variation, all systems were shown to have less than 1000 equivalent thermal cycles. Therefore, the above results confirm the conservatism of the existing stress analyses for Class 2 and 3 systems and was approved by the NRC (NUREG-0843 Supplement 3, April 1983).

Class 2 and 3 piping systems were reviewed for thermal fatigue and confirmed to be acceptable for 60 years of operation. See Section 18.3.2.2.

## 3.9.4 CONTROL ELEMENT DRIVE MECHANISMS

### 3.9.4.1 Descriptive Information of CEDM

The control element drive mechanism (CEDMs) are magnetic jack type drives used to vertically position and indicate the position of the control element assemblies (CEAs) and the part-length control element assemblies (PLCEAs) in the core. Each CEDM is capable of withdrawing, inserting, holding, or tripping the CEA/PLCEA from any point within its 137 inch stroke in response to operation signals.

The CEDM is designed to function during and after all normal plant transients. The design life of the CEDM is defined as ~~40~~ 60 years of operation or 100,000 feet of rod travel without loss of function. The CEDM is designed to operate without maintenance for a minimum of 1-1/2 years and without replacing components for a minimum of three years. The CEDM is designed to function normally during and after being subjected to the operating basis earthquake loads. The CEDM allows for tripping and drive-in of the CEA/PLCEA during and after a safe shutdown earthquake.

The design and construction of the CEDM pressure housings fulfill the requirements of the ASME Code, Section III, Class 1. The CEDM pressure housings are part of the reactor coolant pressure boundary, and they are designed to meet stress requirements consistent with those of the vessel. The pressure housings are capable of withstanding, throughout the design life, all normal operating loads, which include the steady-state and transient operating conditions specified for the vessel. Mechanical excitations are also defined and included as a normal operating load. The CEDM pressure housings are service rated at 2500 psia and 650ºF. The loading combinations and stress limit categories are presented in Subsection 3.9.4.3 and are consistent with those defined in the ASME Code.

The test programs performed in support of the CEDM design are described in Subsection 3.9.4.4.

#### 3.9.4.1.1 Control Element Drive Mechanism Design Description

The CEDMs are mounted and seal welded on nozzles on top of the reactor vessel closure head. The CEDMs consist of the upper and lower CEDM pressure housings, motor assembly, coil stack assembly, reed switch assemblies, and extension shaft assembly. The CEDM is shown on Figure 3.9-11. The drive power is supplied by the coil stack assembly, which is positioned around the CEDM housing. A position indicating reed switch assembly is supported by the upper pressure housing shroud, which encloses the upper pressure housing assembly.

The components outside the pressure boundaries are the coil stack, the pressure housing shroud, and the cooling shroud. All are designed to be a slip fit over the motor housing and are capable of being removed at temperature. A test was performed to verify this requirement. Dimensions and materials used for the St. Lucie 2 CEDMs are identical to those on operating reactors.

TABLE 3.9-2

TRANSIENTS USED IN DESIGN AND FATIGUE ANALYSIS

**NOTE:** Class 1 piping and components were reviewed for thermal fatigue and were confirmed to be acceptable for 60 years of operation, utilizing the original 40-year design cycles. See Section 18.3.2.1.

1. Normal Conditions

(a) 500 heatup and cooldown cycles during the design life of the components with heating and cooling at a rate of 100°F/hr between 70°F and 532°F (653°F for the pressurizer). The heatup and cooldown rate of the system is administratively limited to 75°F/hr to assure that these limits will not be exceeded. This is based on a normal plant cycle of one heatup and cooldown per month rounded to the next highest hundred.

(b) 15,000 power change cycles over the range of 15 percent to 100 percent of full load at 5 percent of full load per minute increasing and decreasing. This is based on a normal plant operation involving one cycle per day for 40 years rounded to the next highest 1000.

(c) 2,000 cycles of step power changes of 10 percent of full load, increasing in the 15 percent to 100 percent of full load range and decreasing in the 100 percent to 25 percent of full load range. This is based on a normal plant operation involving one cycle per week for 50 weeks of the year.

(d) $1 \times 10^6$ cycles of normal variations of - 100 psi and – 6°F when at operating temperature and pressure. This was selected based on 1 x 10 cycles being equivalent to infinite cycles and thus the limiting stress is the endurance limit. - 100 psi is the maximum pressure fluctuation above the setpoint (2235 psig) before backup heaters come on or spray valves open. For conservatism, the temperature cycle developed for the pressurizer is used for all components.

2. Upset Conditions

(a) 40 cycles of complete loss of reactor coolant flow when at 100 percent power. This is based on one reactor trip per year for the life of the plant resulting from failure of electrical supply to the reactor coolant pumps.

(b) 400 reactor trips from full load. This is based on one reactor trip per month for the life of the plant and includes trips due to operator error and equipment failure.

(c) 40 cycles of turbine trip from 100 percent power with delayed reactor trip. This is based on one reactor trip per year for the life of the plant considering failure of the turbine trip/ reactor trip circuit as credible.

TABLE 3.9-3A

A/E SUPPLIED QUALITY GROUP A TRANSIENTS

| PLANT EVENT | LIFETIME OCCURRENCES | COMPONENT* CONDITION |
|---|---|---|
| Plant Cooldown | 500 | N |
| Plant Hheatup | 500 | N |
| Power Operation | - | N |
| Loading/Unloading<br>Ramp 5% per Min<br>Step 10% | <br>15,000<br>2,000 | |
| Reactor Trip | 400 | U |
| Hydro Static Tests, (3125 psia) | 10 | T |
| Leak Test, (2250 psia) | 200 | T |
| Normal Pressure Variation ($\pm$ 100 psi, $\pm$ 7° F) | $10^6$ | N |
| Loss of Primary Flow | 40 | U |
| Loss of Secondary Pressure | 5 | E |
| Loss of Turbine-Gen. Load | 40 | U |
| Purification, & Boron Dilution (CVCS) | 24,000 | N |
| Loss of Charging Flow (CVCS) | ~~20~~ 100 | U |
| Regenerative Heat Exchanger Isolation and Loss of Letdown (CVCS) | ~~50~~ 270 | U |
| Isolation Check Valve Leaks | 40 | U |

*Definitions of the events Normal (N), Upset (U), Emergency (E), Faulted (F) and Test (T) are given in ASME III, Para. NB-3113.

b) Non safety electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions specified previously.

c) Certain post-accident monitoring equipment (Refer to Regulatory Guide 1.97, Revision 3, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs During and Following an Accident."

These components are identified and controlled on plant drawing 2998-A-450.

### 3.11.4 QUALIFICATION OF COMPONENTS

If the equipment in question meets the requirement found in Subsection 3.11.3, it must be qualified to 10CFR.50.49. The "Environmental Qualification Report and Guidebook," Drawing 2998-A-451-1000 provides the information required to properly identify the environment to which the specific equipment must be qualified. Operability requirements associated with the component are discussed along with the required temperature, pressure, humidity, radiation, aging and submergence.

Each parameter is defined in a specific subsection. Most parameters are identified on Zone Maps as a convenient reference. Zone Maps indicate the normal and abnormal values associated with specific areas of the plant at a given period of time.

Harsh environments are characterized by abnormally high temperatures and pressures, high radiation doses, corrosive chemical spray, and/or high relative humidity. Also, in some cases, submergence may have to be considered based on equipment location with respect to the maximum flood level.

A mild environment, as defined in 10CFR50.49, is an environment that would at no time be significantly more severe than the environment which would occur during normal operation, including operational occurrences. Equipment located in a mild environment is not covered under 10CFR50.49. Mild environments operability is assured by either: (a) periodic maintenance, inspection and/or a replacement program based on sound engineering judgement or manufacturer's recommendations; (b) a periodic testing program; (c) an equipment surveillance program.

Environments in which radiation is the only parameter of concern are considered to be mild if the total radiation dose (includes ~~40~~ 60-year normal dose plus the post accident dose) is 1.0E5 rads or less. This value is the threshold for evaluation and consideration. Excluded from this consideration, however, are most solid state electronic components and components that utilize teflon. Class IE equipment located in environments between 1.0E3 and 1.0E5 are evaluated on a case by case basis.

For additional detail on the identification of environmental conditions refer to Drawing 2998-A-451-1000," Environmental Qualification Report and Guidebook."

3.11.5 MAINTENANCE

The purpose of the St. Lucie Unit 2 Equipment Qualification Program is the preservation of the qualification of safety related systems, structures and components. In order to accomplish the task, the plant has developed approved Design Control, Procurement and Maintenance Procedures. Each procedure has incorporated the requirements of environmental qualification according to the functional requirements of the program/system/component. The plants procedures are prepared to maintain proper design control, for plant modifications, procurement of new equipment and spare parts. The plants maintenance program is designed to provide preventative as well as corrective maintenance which is identified by field operational experience and industry correspondence. In addition, the component specific documentation package contains, in Section 5, the equipments qualified life. This qualification interval is developed based upon the vendors test report reviewed in conjunction with the environmental parameter associated with the area. After this review is completed a qualified life is established and operation with this piece of equipment up to the equipments end point is acceptable.

3.11.6 RECORDS/QUALITY ASSURANCE

A documentation package is prepared for the qualification of each manufacturers piece of equipment under the auspices of 10CFR50.49. This package contains the information, analysis and justifications necessary to demonstrate that the equipment is properly and validly qualified for the environmental effects of ~~40~~ 60 years of service plus a design basis accident.

This documentation package is developed from the criteria stipulated in the Environment Qualification Report and Guidebook.

A complete listing of equipment under the auspices of 10CFR50.49 is maintained.

All three of the above documents are drawings and are developed and controlled under the procedures involving drawing preparation, updating and storage as specified in the FPL Quality Assurance Program.

The generic elements of the FPL Quality Assurance Program are described in the Florida Power and Light Topical Quality Assurance Report (FPLTQAR). The FPLTQAR defines departmental responsibilities by which FPL implements the corporate Quality Assurance program, and is an integral part of the corporate Quality Assurance Manual.

3.11.7 CONCLUSIONS

The Equipment Qualifications Report and Guidebook, together with the manufacturers' specific Documentation Packages and the 10CFR50.49 list of equipment have been developed for the purpose of documenting the environmental qualification of safety related equipment. This program has insured the systems selected for qualification are complete, the environmental conditions resulting from the design basis accident are indentified and that the methods used for qualification are appropriate.

Based on these checks and the ongoing environmental qualification program, St. Lucie Unit 2 is in compliance with 10CFR50.49.

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# CHAPTER 4 CHANGES

4.3.2.8 Vessel Irradiation

The design of the reactor internals and of the water annulus between the active core and vessel wall is such that for reactor operation at the full power rating and an 80 percent capacity factor, the vessel fluence greater than one MeV at the vessel wall will not exceed 4.9 ~~3.66~~ x $10^{19}$ n/cm$^2$ over the ~~40~~ 60-year design life of the vessel. The calculated exposure includes a 10 percent uncertainty factor.

The maximum fast neutron fluxes greater than one MeV incident on the vessel ID and shroud ID are as shown in Table 4.3-10. The fluxes are based on a time averaged equilibrium cycle radial power distribution and an axial power distribution with a peak to average of 1.20. The calculation assumed a thermal power of 2700 MWt. The models used in these calculations are discussed in Subsection 4.3.3.3.

4.3.3 ANALYTICAL METHODS

Discussions of methodologies within this section are written from an historic perspective and may have been superseded by newer methods as discussed in Reference 65.

Beginning with Cycle 12, Westinghouse physics methodology is used to generate physics inputs and characteristics based on Reference 69.

4.3.3.1 Reactivity and Power Distribution

4.3.3.1.1 Method of Analysis (HISTORICAL)

The nuclear design analysis for low enrichment PWR cores is based on a combination of multigroup neutron spectrum calculations, which provide cross sections appropriately averaged over a few broad energy groups, and few group one, two, and three dimensional diffusion theory calculations of integral and differential reactivity effects and power distributions. The multigroup calculations include spatial effects in those portions of the neutron energy spectrum where volume homogenization is inappropriate; e.g., the thermal neutron energy range. Most of the calculations are performed with the aid of computer programs embodying analytical procedures and fundamental nuclear data consistent with the current state of the art.

Comparisons between calculated and measured data that validate the design procedures are presented in Subsection 4.3.3.1.2. As improvements in analytical procedures are developed, and improved nuclear data become available, they will be added to the design procedures, but only after validation by comparison with related experimental data.

Few group cross sections for subregions of the core that are represented in spatial diffusion theory codes, e.g., fuel pin cells, moderator channels, structural member cells, etc., are calculated by the CEPAK lattice program. This program is the synthesis of a number of computer codes, many which were developed elsewhere; e.g., FORM,[3] THERMOS[4] and CINDER.[5] These programs are interlinked in a consistent way with inputs from differential cross-section data from an extensive library.

The microscopic data base for both fast and thermal neutron cross-section is derived from the Evaluated Nuclear Data File ENDF/B-IV. Some modifications have been applied to the U-238 resonance integral to correct for a recognized overestimation of that quantity in ENDF/B-IV.

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# CHAPTER 5 CHANGES

TABLE 5.3-9

CAPSULE ASSEMBLY REMOVAL SCHEDULE[e]

| ~~Capsule No.~~ | ~~Azimuthal~~ Location on Vessel Wall | Approximate Removal Time (EFPY) | Predicted Fluence ($n/cm^2$) | Lead Factor[d] |
|---|---|---|---|---|
| ~~1~~ | 83° | 1.11 [a] | $1.779 \times 10^{18}$ | ~~≤1.5~~ ------ |
| ~~2~~ | 97° | ~~24~~ 26 | $2.70 \times 10^{19}$ | ~~≤1.5~~ 1.27 |
| ~~3~~ | 104° | Standby[c] | ------ | ~~≤1.5~~ 0.98 |
| 4 | 263° | 11[b] | $1.244 \times 10^{19}$ | ~~≤1.5~~ ------ |
| ~~5~~ | 277° | 44/Standby[c] | $4.56 \times 10^{19}$ | ~~≤1.5~~ 1.27 |
| ~~6~~ | 284° | Standby[c] | ------ | ~~≤1.5~~ 0.98 |

a. Actual removal time (Reference 5- Babcock & Wilcox Report # BAW-1880, Sept. 1985).

b. Actual removal time (Reference 6- Westinghouse Report # WCAP-15040, April 1998).

c. As required by ASTM E185, ~~O~~one standby capsule will be removed at the end of license fluence and available for testing. ~~per ASTM E185-82~~.

d. Lead Factor is defined as the capsule fluence/RV base metal peak fluence (Reference 6).

e. Capsule removal schedule changes require NRC approval per 10 CFR 50, Appendix H.

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requires that the radiolytic and pyrolytic characteristics of the protective coatings are tested, analyzed, and certified, in accordance with the above ANSI Standards, that no decomposition products will be released such as to interfere with the safe operation of any engineered safety feature. The physical-chemical characteristics of the above protective coatings are ensured by tests, conducted per ANSI Standards N512 and N101.2, to show that combustible properties are at or below the acceptable level delineated in those ANSI Standards. Tests deemed necessary to demonstrate satisfactory performance have been conducted.

Application of field applied coatings is done in compliance with the recommendations of each product manufacturer and per approved site-coating procedures. Quality assurance during manufacturing, storage, application and inspection of field applied coatings meets the intent of ANSI Standard N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," Nov. 1972, in conjunction with the general QA requirements of ANSI N45.2, Oct. 1971, and thereby are consistent with the requirements of Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water Cooled Nuclear Power Plants" June 1973.

Protective coatings ~~are~~ were originally intended for a 40 year service life. Consistent with St. Lucie's response to NRC Generic Letter 98-04 (see Section 6.3.2.2.2a), visual inspections and condition assessments of Service Level 1 coatings inside the containment building are performed every refueling outage. In the event that recoating is desired, the original coating is removed before application of any new coating. Note that coating parameters (i.e., thermal conductivity, thickness and volumetric heat capacity) are used in the accident analysis of Section 6.2.1.

The total amount of protective coatings and organic materials used inside the containment that do not meet the requirements of ANSI N101.2 (1972) and Regulatory Guide 1.54 is approximately 6 cubic feet. The amount of unqualified protective coatings is about 2.5 cubic feet. The equipment so coated is located in various parts of the containment. Although these coating schemes have not undergone DBA qualification testing, some of these coating schemes are baked on enamel which will not readily peel off under DBA environments. The remaining unqualified organic material is NUKEM 750 caulking material used as expansion joint filler (2.5 cubic feet) and miscellaneous organics (approximately 1 cubic foot). Use of NUKEM 750 was justified and was deemed acceptable by the NRC. [(1),(2)]

Evaluation of the effect of unqualified materials inside containment on combustible gas generation can be found in Subsection 6.2.5 and on ECCS sump screen design in Subsection 6.2.2.

In addition to the redundant CGCS, the Continuous Containment Purge/hydrogen Purge System is available for fission product removal and hydrogen purge following a LOCA.

6.2.5.2 System Design

6.2.5.2.1 Containment Hydrogen Analyzer Subsystem

The Containment Hydrogen Analyzer System consists of two redundant subsystems as shown on Figure 6.2-62, consisting of the sample and return piping, associated valves, hydrogen analyzer, grab sample cylinder, sample pump, moisture separator, cooler, instruments, calibration gas line and reagent gas line.

Each of the redundant subsystems is physically separate and operates independently of the other, and is powered from an independent onsite power source. No single failure can result in a total loss of hydrogen concentration measurement capability. Failure of one train is annunciated in the control room.

Components of the system are accessible for periodic inspection and maintenance. The system is designed to permit remote calibration at periodic intervals with a reference hydrogen gas standard (span gas) and oxygen. The system is independent of any system used during normal plant operation so that plant operation does not impose restrictions on such testing.

The Hydrogen Analyzer System piping, from the sample points within the Containment and piping returning the sample to the Containment, up to and including all containment isolation valves, are designed and fabricated in accordance with ASME Section III Class 2 and N-stamped. The hydrogen analyzer package contains instrumentation elements which are inherently non-ASME, code items (e.g., flowmeters, pressure gages, and the analyzer element). Therefore, the hydrogen analyzer package is classified as a Class IE instrument. Instrumentation, controls and electric equipment associated with the system will be Class IE. Conformance to applicable IEEE Standards is discussed in Chapter 7.

The system is initiated by manual operator action from the control room. No action outside the control room is necessary for system operation.

Once initiated, the system draws a continuous air sample from one of the sample points inside containment. Sampling valves can be manually controlled to analyze any sample point. The air is passed through the detector, analyzed, and pumped back into containment. Analyzer readings are recorded in the control room, and an alarm is actuated if concentration is above three percent. Alarm is also provided for low flow and low temperature in the analyzer hot box. Design and performance date for the analyzer is listed in Table 6.2-54.

The system is designed ~~for 40 years of normal and one year post-LOCA environmental condition~~ and the components are qualified to operate under the applicable environmental conditions as described in Section 3.11.

tainment fan coolers and their associated ductwork as discussed in Subsection 6.2.2.2.2 by the turbulence introduced by the containment sprays, and by the process of natural diffusion of combustible gas with the containment air. Air is drawn into the recombiner by natural convection and passes first through the preheater section. This section consists of a shroud placed around the central heater section to take advantage of heat conduction through the walls to preheat the incoming air. This accomplishes the dual functions of reducing heat losses from the recombiner and of preheating the air.

The warmed air passes through an orifice plate and then enters the electric heater section where it is heated to approximately 1150ºF to 1400ºF causing recombination to occur. The flow then enters the cooling/exhausting section where the stream is mixed and diluted with cooler containment air in order to discharge the stream back into the containment atmosphere at a lower temperature.

Each hydrogen recombiner system has a removal capacity which is sufficient to limit concentrations of gases within the containment to safe concentrations; i.e., concentrations below the flammability limits. After a threehour startup period, the recombiner efficiency is 99-100 percent and the effluent does not exceed 100 F above ambient.

The unit is manufactured primarily of corrosion-resistant, high-temperature material for major structural components, except for the base which is steel. The electric hydrogen recombiner used conventional type electric resistance heaters sheathed with Incoloy-800 which is an excellent corrosion resistant material for this service. These heaters are designed to operate with sheath temperatures equal to those used in certain commercial heaters; however, these recombiner heaters operate at significantly lower power densities than in commercial practice.

The recombiners are located on the elevation 62.0 ft. of the containment. They are inaccessible following a LOCA, and as such there is no sharing of recombiners among St Lucie Units 1 and 2 or with other facilities. The hydrogen recombiners are designed for ~~40~~ <u>60</u> years normal and one year post LOCA conditions. Design and performance data for the recombiners are listed in Table 6.2-55.

Each of the two recombiners is 100 percent capacity, and is connected to a separate onsite power source so that no single failure results in a total loss of recombiner function.

The recombiner is started by the operator by manual action from the control room. The operator is alerted when the containment $H_2$ level reaches three volume percent as signaled by the redundant Class IE alarms of the Containment Hydrogen Analyzer System. Plant procedures provide guidance to the operator on when to start the hydrogen recombiner following a LOCA.

6.2.5.2.3 Containment Hydrogen Purge System

The Continuous Containment Purge/Hydrogen Purge System is provided as a further possible means of controlling hydrogen inside the containment following a LOCA. This system is provided as required by the NRC, although no single failure following a LOCA would necessitate its use. Therefore, the system

6.3.2.2.3 High Pressure Safety Injection Pumps

The primary function of a high-pressure safety injection (HPSI) pump is to inject borated water into the Reactor Coolant System if a break occurs in the Reactor Coolant System boundary. For small pipe breaks, the Reactor Coolant System pressure remains high for a long period of time following the accident, and the high pressure safety injection pumps ensure that the injected flow is sufficient to meet the criteria given in Subsection 6.3.1. The high-pressure safety injection pumps are also used during the recirculation mode to maintain a borated water cover over the core for extended periods of time. For long term core cooling, the HPSI pumps are manually realigned for simultaneous hot and cold leg injection. This insures flushing and ultimate subcooling of the core coolant independent of break location. For small pipe breaks, the HPSI pumps continue injecting into the Reactor Coolant System to provide makeup for spillage out the break while a normal cooldown is implemented.

The St. Lucie 2 HPSI pumps are manufactured by Bingham-Willamette Company. These pumps are similar in design to conventional boiler feed pumps where continuous service over a broad range of temperature is required. Specific long-term testing of the HPSI pumps was not required because of the vendors experience with the design.

~~The St Lucie 2 HPSI pumps have a design lifetime of 40 years, consistent with the plant design basis.~~ Operational testing is considered as part of the functional requirements of the pump. For the purpose of pump specification and design, the long-term LOCA requirement is defined as continuous operation for up to one year at runout conditions. The operational experience of the pump vendor on similar equipment is defined below.

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h) Primary System Pressure Deviation

The assignment of an initiating event to one of these eight event types is made by collecting initiating events with the same major effect and similar occurrence rates into an Event Group. Each Event Group is then assigned to one of the above eight event types based on its primary impact on the NSSS. Table 15.0-1 lists all of the Event Groups and initiating events considered in the St Lucie Unit 2 accident analysis.

15.0.1.3 Frequency Groups

The five frequency groups used in the type/frequency matrix are listed below:

a) Moderate Frequency Event

A Moderate Frequency event may occur during a calendar year for a particular plant. ~~It is assumed that a Moderate Frequency event has at least a 50 percent probability of occurring in any calendar year for a particular plant.~~

b) Infrequent Event

An Infrequent event may occur during the lifetime of a particular plant. ~~It is assumed that an Infrequent event has less than a 50 percent probability of occurring in any calendar year, but at least a 50 percent probability of occurring in the assumed 40 year lifetime for a particular plant.~~

c) Limiting Fault

A Limiting Fault is not expected to occur during the lifetime of a particular plant. ~~It is assumed that a Limiting Fault has less than a 50 percent probability of occurring in the assumed 40 year plant lifetime, but at least a $10^{-6}$ probability of occurring in any calendar year.~~ This broad frequency group is divided into three subgroups to allow comparison of events with similar frequencies. These three subgroups of Limiting Faults are consistent with the acceptance guideline divisions suggested by the Standard Review Plan[2] (See Subsection 15.0.1.7). The subgroups are defined below:

C.1 Limiting Fault - 1

A Limiting Fault - 1 event has a low probability of occurring during the ~~assumed 40 year~~ lifetime for a particular plant.

C.2 Limiting Fault - 2

A Limiting Fault - 2 event has a very low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

C.3 Limiting Fault - 3

A Limiting Fault - 3 event has an exceedingly low probability of occurring in the ~~assumed 40-year~~ lifetime for a particular plant.

15.0.1.4 Event Group Frequencies

The estimated frequency of occurrence of an Event Group is calculated from the sum of reported occurrences of the initiating events in that Event Group as observed in United States commercial PWR plants or from other non-nuclear related experience, i.e., high energy pipe break data. Conservative factors are applied to the estimated frequencies to determine a conservative upper bound frequency, referred to as the expected frequency of occurrence of an Event Group. (All initiating events in an Event Group are assumed to have the expected frequency of occurrence of the Event Group for the purpose of applying the acceptance guidelines.) The expected frequency serves as the basis for assigning each Event Group to one of the five frequency groups defined in Subsection 15.0.1.3. Table 15.0-2 shows all Event Groups positioned on the type/frequency matrix.

15.0.1.5 Event Combinations

Additional failures and/or special plant conditions are combined (via event tree analysis) with initiating events to generate event combinations. The frequency of and event combination is calculated by combining the expected frequency of an initiating event and the conditional probability of each additional failure or special plant condition. The resultant frequency serves as the basis for assigning event combinations to one of the five frequency groups defined in Subsection 15.0.1.3.

Additional failures are divided into the following four groups:

a) High-probability dependent occurrences

b) Low-probability dependent occurrences

c) High-probability independent occurrences

d) Low-probability independent occurrences

A dependent occurrence is an action which occurs as a direct result of an initiating event. All high probability dependent occurrences (e.g., turbine trip on reactor trip) are assigned a probability of one and are included in the definition of the initiating event.

An independent occurrence is a random, pre-existing failure, i.e., a failure which has occurred some time before an initiating event. The impact of this failure is not apparent until an initiating event causes the system containing the failure to perform an action which cannot be performed correctly.

## 15.2.5 LIMITING FAULT-3 EVENTS

### 15.2.5.1 Limiting Offsite Dose Event

None of the LF-3 event group and event group combinations resulting in a decreased heat removal by the secondary system shown in Table 15.2.5-1 release a significant amount of radioactivity to the atmosphere. The site boundary dose which would occur during the most adverse of these event groups or event combinations is well within the acceptance guideline specified in Table 15.0-4.

#### 15.2.5.1.1 Feedwater Line Break Event (Reload Cycles)

Feedwater system pipe breaks are analyzed to confirm that the reactor primary system is maintained in a safe status for a range of feedwater line breaks up to and including a break equivalent in area to the double-ended rupture of the largest feedwater line. In the following discussion, feedwater line breaks will be categorized as small or large.

A large feedwater line break is any feedwater line break with an equivalent break area greater than 0.2 $ft^2$ (equivalent break size greater than a double-ended rupture for a 6 inch diameter pipe). Based on the nuclear industry piping experience information in WASH-1400 (Reference 4), the EPRI Utility Requirements Document (Reference 5), and the EPRI Piping Failure Study (Reference 6), the recurrence frequency for a large feedwater line break was estimated to be on the order of $1 \times 10^{-4}$ per year. Therefore, a large feedwater line break with an equivalent break area greater than 0.2 $ft^2$ is an event with a very low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

The nuclear industry operating experience information in WASH-1400 (Reference 4), the EPRI Utility Requirements Docment (Reference 5), and the EPRI Piping Failure Study (Reference 6) was used to determine the recurrence frequency for any feedwater line break with a concurrent loss of offsite power on reactor trip. The probability of a loss of offsite power was estimated to be $1 \times 10^{-3}$ and the recurrence frequency for feedwater line breaks of any size was estimated to be $6.2 \times 10^{-3}$ per year. Based on this data, the frequency for any feedwater line break with a concurrent loss of offsite power on reactor trip is an event with an exceedingly low probability of occurring in the ~~assumed 40 year~~ lifetime for a particular plant.

##### 15.2.5.1.1.1 Small Feedwater Line Break Event (Reload Cycles)

###### 15.2.5.1.1.1.1 Identification of Causes

The Small Feedwater Line Break Event was Analyzed to ensure that the site boundary doses would not exceed a small fraction of the 10CFR100 guidelines and that the peak RCS pressure would not exceed the upset pressure limit of 2750 psia.

A Feedwater Line Break Event is defined as the failure of a main feedwater system pipe during plant operation. A rupture in the main feedwater system rapidly reduces the steam generator secondary inventory causing a partial loss of the secondary heat sink, thereby allowing heat up of the Reactor Coolant System (RCS). The RCS is protected from over-pressurization by the high pressurizer pressure trip and the pressurizer safety valves.

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# CHAPTER 18.0
# [NEW]

# 18.0 AGING MANAGEMENT PROGRAMS AND TIME-LIMITED AGING ANALYSES ACTIVITIES

The integrated plant assessment for license renewal identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This chapter describes these programs and their planned implementation.

This chapter also discusses the evaluation results for each of the plant-specific time-limited aging analyses performed for license renewal. The evaluations have demonstrated that: the analyses remain valid for the period of extended operation; the analyses have been projected to the end of the period of extended operation; or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

No 10 CFR 50.12 exemptions involving a time-limited aging analysis as defined in 10 CFR 54.3 were identified for St. Lucie Unit 2.

## 18.1 NEW PROGRAMS

### 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 in select systems will be performed and evaluated to establish if the corrosion mechanism is active. Based on the results of these inspections, the need for follow-up examinations or programmatic corrective actions will be established. This new program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

### 18.1.2 PIPE WALL THINNING INSPECTION PROGRAM

The Pipe Wall Thinning Inspection Program manages the aging effect of localized loss of material due to erosion of the internal surfaces of stainless steel Auxiliary Feedwater System piping downstream of the recirculation orifices, and carbon steel Component Cooling Water System piping associated with control room air conditioning. Examinations will be performed using volumetric techniques such as ultrasonic testing or radiography. The initial inspection will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

## 18.1.3 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

The Reactor Vessel Internals Inspection Program manages the aging effects of irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness, loss of mechanical closure integrity of bolted joints, and dimensional changes due to void swelling. The program consists of a one-time VT-1 visual examination and, in some cases, enhanced VT-1 examinations of selected reactor vessel internals parts to be performed during the second half of the period of extended operation. This inspection will be performed in addition to and in conjunction with the examinations required by the St. Lucie ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The examinations will be focused on areas of potential aging effects based on the highest projected combination of stress and fluence. For cast austenitic stainless steel (CASS) parts, analytical methods will be used to identify reactor vessel internals parts that are susceptible to loss of fracture toughness due to thermal embrittlement.

FPL will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial 40-year operating license term for St. Lucie Unit 1. This report will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks and acceptance criteria.

## 18.1.4 SMALL BORE CLASS 1 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 the NRC with a report describing this inspection plan prior to its implementation. The inspection will be performed prior to the end of the initial operating license term for St. Lucie Unit 2.

## 18.1.5 THERMAL AGING EMBRITTLEMENT OF CASS PROGRAM

The St. Lucie Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will include a determination of the susceptibility of Class 1 CASS piping components to thermal aging embrittlement and will provide for the subsequent aging management of those components that have been identified as being potentially susceptible. Aging management, if required, will be accomplished through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. This program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

# 18.2 EXISTING PROGRAMS

## 18.2.1 ALLOY 600 INSPECTION PROGRAM

This program manages the aging effect of cracking due to primary water stress corrosion (PWSCC) for susceptible Alloy 600 components within the Reactor Coolant System (RCS) pressure boundary. This includes the reactor vessel head penetration nozzles, reactor head vent pipe, pressurizer instrument nozzles and heater sleeves, control element drive mechanism motor housing lower end fittings, RCS piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray piping fittings and RCS piping dissimilar metal welds. The program includes examinations of the reactor vessel head penetrations to detect crack initiation consistent with St. Lucie Plant's response to NRC Bulletin 2001-01 and on-going Nuclear Energy Institute (NEI) and Electric Power Research Institute (EPRI) Materials Reliability Project recommendations. Visual examination of external surfaces of susceptible locations during outages, which is included as part of the Boric Acid Wastage Surveillance Program, is also utilized to manage cracking.

## 18.2.2 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

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

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program inspections identify and correct degradation in Class 1, 2, and 3 components and piping. The program manages the aging effects of loss of material, cracking, loss of preload, reduction in fracture toughness, and loss of mechanical closure integrity. The program provides for inspection and examination of accessible components, including the reactor vessel, reactor vessel internals, steam generators, welds, pump casings, valve bodies, steam generator tubing, and pressure-retaining bolting.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and to require VT-1 inspections of the core stabilizing lugs and core support lugs. This action will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

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

ASME Section XI, Subsection IWE Inservice Inspection Program inspections identify and correct degradation of pressure-retaining components and their integral attachments to the Class MC steel Containments. The program manages the aging effects of loss of material and loss of seal. The program provides for inspection and examination of Containment surfaces, pressure-retaining welds, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure-retaining components in accordance with the requirements of ASME Section XI, Subsection IWE.

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

ASME Section XI, Subsection IWF Inservice Inspection Program inspections identify and correct degradation of ASME Class 1, 2, and 3 component supports. This program manages the aging effect of loss of material. The scope of the program provides for inspection and examination of accessible surface areas of the component supports in accordance with the requirements of ASME Section XI, Subsection IWF.

## 18.2.3 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

The Boric Acid Wastage Surveillance Program manages the aging effects of loss of material and loss of mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. The program addresses the RCS and structures and components containing, or exposed to, borated water. This program utilizes systematic inspections, leakage evaluations, and corrective actions to ensure that boric acid corrosion does not lead to degradation of the pressure boundary or the structural integrity of components, supports, or structures in proximity to borated water systems. This program includes commitments in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

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

## 18.2.4 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program manages the aging effects of loss of material, cracking, and fouling for primary and secondary systems, closed cooling water, and fuel oil systems, structures, and components. The aging effects are minimized or prevented by controlling the chemical species that cause the underlying mechanism(s) that results in these aging effects. Alternatively, chemical agents, such as corrosion inhibitors and biocides, are introduced to prevent certain aging effects. The program includes sampling activities and analysis. The program provides assurance that elevated levels of contaminants and oxygen do not exist in the systems, structures, and components covered by the program, and thus prevents and minimizes the occurrences of aging effects.

## 18.2.5 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification Program is not credited as an aging management program; however, program evaluations of electrical equipment are identified as time-limited aging analyses.

Equipment covered by the Environmental Qualification Program has been evaluated to determine if the existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment initially qualified for 40 years or less. When analysis cannot justify a qualified life in excess of the license renewal period, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life in accordance with the Environmental Qualification Program.

## 18.2.6 FATIGUE MONITORING PROGRAM

The Fatigue Monitoring Program is considered a confirmatory program to ensure that fatigue time-limited aging analysis assumptions remain valid for the period of extended operation; it is not credited as an aging management program.

The Fatigue Monitoring Program is designed to track design cycles to ensure that RCS components remain within their design fatigue limits. Design cycle limits for St. Lucie Unit 2 are provided in Sections 3.9.3.1 and 5.4.2.1. The specific fatigue analyses validated by the Fatigue Monitoring Program are associated with the reactor vessel, reactor vessel internals, pressurizer, steam generators, reactor coolant pumps, and Class 1 RCS piping. Administrative procedures provide the methodology for logging design cycles. These procedures will be enhanced to provide guidance in the event design cycle limits are approached. This action will be completed prior to the end of the initial operating license term for St. Lucie Unit 2.

## 18.2.7 FIRE PROTECTION PROGRAM

The Fire Protection Program manages the aging effect of loss of material for the components of the Fire Protection System. Additionally, this program manages the aging effect of loss of material for structural components associated with fire protection. Appendix 9.5A contains a detailed discussion of the Fire Protection Program.

## 18.2.8 FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion Program manages the aging effect of loss of material due to flow accelerated corrosion. The Flow Accelerated Corrosion Program predicts, detects, monitors, and mitigates flow accelerated corrosion in high energy carbon steel piping associated with the Main Steam, Reactor Coolant (steam generators), Main Feedwater, and Steam Generator Blowdown Systems, and is based on industry guidelines and experience. The program includes analysis and baseline inspections; determination, evaluation, and corrective actions for affected components; and follow-up inspections.

The Flow Accelerated Corrosion Program will be enhanced to address internal and external loss of material of selected steam trap lines due to flow accelerated corrosion and external general corrosion. This action will be completed prior to the end of the initial operating license term for St. Lucie Unit 2.

## 18.2.9 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

The Intake Cooling Water System Inspection Program manages the aging effects of loss of material due to various corrosion mechanisms, and particulate and biological fouling for Intake Cooling Water (ICW) System components and the ICW side of the Component Cooling Water heat exchangers. The program includes inspections, performance testing, evaluations, and corrective actions that are performed as a result of FPL commitments in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

## 18.2.10 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of loss of material, cracking, loss of seal, and fouling (mechanical components only) for various plant systems, structures, and components. The scope of the program provides for visual examination of selected surfaces of specific systems, structures, and components. Additionally, the program provides for replacement/refurbishment of selected components on a specified frequency, as appropriate, and periodic sampling and water removal from hydraulic accumulators and fuel oil storage tanks. The frequency of inspections varies depending on the specific component, the aging effect being managed, and plant operating experience.

Specific enhancements to the scope of this program will be implemented prior to the end of the initial operating license term for St. Lucie Unit 2.

## 18.2.11 REACTOR VESSEL INTEGRITY PROGRAM

The Reactor Vessel Integrity Program manages reactor vessel irradiation embrittlement and encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure-Temperature Limit Curves

Program documentation will be enhanced to integrate aspects of the Reactor Vessel Integrity Program prior to the end of the initial operating license term for St. Lucie Unit 2.

### 18.2.11.1 REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION

This subprogram manages the aging effect of reduction in fracture toughness of the reactor vessel materials (beltline plates and welds) due to neutron irradiation embrittlement by performing Charpy V-notch and tensile tests on the reactor vessel irradiated specimens. The Reactor Vessel Surveillance Capsule Removal and Evaluation subprogram is an NRC-approved program that meets the requirements of 10 CFR 50, Appendix H. The surveillance capsule withdrawal schedule is specified in Table 5.3-9.

#### 18.2.11.2 FLUENCE AND UNCERTAINTY CALCULATIONS

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline plates welds.

#### 18.2.11.3 MONITORING EFFECTIVE FULL POWER YEARS

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessel to ensure that the pressure-temperature limits and end-of-life reference temperatures are not exceeded.

#### 18.2.11.4 PRESSURE-TEMPERATURE LIMIT CURVES

This subprogram provides pressure-temperature limit curves for the reactor vessel to establish the RCS operating limits. The pressure-temperature limit curves are included in the Technical Specifications.

### 18.2.12 STEAM GENERATOR INTEGRITY PROGRAM

The Steam Generator Integrity Program is consistent with the guidelines provided by the Nuclear Energy Institute's NEI 97-06, "Steam Generator Program Guidelines." The program ensures that steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The program manages the aging effects of cracking and loss of material.

### 18.2.13 SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, loss of seal, and change in material properties. The program provides for periodic visual inspection and examination for degradation of accessible surfaces of specific systems, structures, and components, and corrective actions, as required, based on these inspections.

This program will be enhanced to provide guidance for managing the aging effects of inaccessible concrete, inspection of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion. These enhancements will be made prior to the end of the initial operating license term for St. Lucie Unit 2.

# 18.3 TIME-LIMITED AGING ANALYSIS ACTIVITIES

## 18.3.1 REACTOR VESSEL IRRADIATION EMBRITTLEMENT

The St. Lucie Unit 2 reactor vessel is described in Chapters 4 and 5. Time-limited aging analyses (TLAAs) applicable to the reactor vessel are:

- pressurized thermal shock
- upper-shelf energy
- pressure-temperature limits

The Reactor Vessel Integrity Program, described in Subsection 18.2.11, manages reactor vessel irradiation embrittlement utilizing subprograms to monitor, calculate, and evaluate the time-dependent parameters used in the aging analyses for pressurized thermal shock, Charpy upper-shelf energy, and pressure-temperature limits to ensure continuing vessel integrity through the period of extended operation.

### 18.3.1.1 PRESSURIZED THERMAL SHOCK

The requirements in 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature ($RT_{PTS}$) whenever a significant change occurs in projected values of $RT_{PTS}$, or upon request for a change in the expiration date for the operation of the facility.

The calculated $RT_{PTS}$ values that bound the 60-year period of operation for the St. Lucie Unit 2 reactor vessel are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the reactor vessel during the license renewal period.

The analysis associated with pressurized thermal shock has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 18.3.1.2 UPPER-SHELF ENERGY

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50, Appendix G. Specifically, 10 CFR 50, Appendix G, requires licensees to submit an analysis at least 3 years prior to the time that the USE of any reactor vessel material is predicted to drop below 50 ft-lbs, as measured by Charpy V-notch specimen testing.

An evaluation was performed to demonstrate continued acceptable margins of safety against fracture through the end of the period of extended operation. All reactor vessel beltline material USE projections remain acceptably above the 10 CFR 50, Appendix G, limit of 50 ft-lbs at the end of the 60-year period of operation using a conservative bounding fluence.

The analysis associated with USE has been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

#### 18.3.1.3 PRESSURE-TEMPERATURE LIMITS

The requirements in 10 CFR 50, Appendix G, stipulate that heatup and cooldown of the reactor pressure vessel be accomplished within established pressure-temperature limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel becomes embrittled and its fracture toughness is reduced, the allowable pressure is reduced. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within the limits of Appendix G defined by the reactor vessel fluence.

The heatup and cooldown pressure-temperature limits are presented in the Unit 2 Technical Specifications. The pressure-temperature curves will be updated as the operating schedule requires. In addition, low temperature overpressure protection (LTOP) requirements will be updated to ensure that the pressure temperature limits are not exceeded for postulated plant transients.

The analyses associated with reactor vessel pressure-temperature limits for St. Lucie Unit 2 will be available prior to entering the period of extended operation, in accordance with the requirements of the Reactor Vessel Integrity Program and consistent with 10 CFR 54.21(c)(1)(ii).

### 18.3.2 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as TLAAs for St. Lucie Unit 2. Specific components have been designed considering design cycle assumptions, as listed in vendor specifications and in Section 3.9.3.

#### 18.3.2.1 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 1 COMPONENTS

The reactor vessel (including control element drive mechanisms), reactor vessel internals, pressurizer, steam generators, reactor coolant pumps, and reactor coolant piping have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III. The pressurizer surge line was reanalyzed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." The design code requires a design analysis to address fatigue and establish limits such that initiation of fatigue cracks is precluded.

Fatigue usage factors for critical locations in the St. Lucie Unit 2 Nuclear Steam Supply System Class 1 components were determined using design cycles that were specified in the plant design process or as a result of industry fatigue issues (e.g., thermal stratification). These design cycles were intended to be conservative and bounding for all foreseeable plant operational conditions. The design cycles were subsequently utilized in the design stress reports for the Class 1 components satisfying ASME fatigue usage design requirements.

Experience has shown that actual plant operation is often very conservatively represented by these design cycles. The use of actual operating history data allows the quantification of these conservatisms in the existing fatigue analyses. To demonstrate that the Class 1 component fatigue analyses remain valid for the period of extended operation, the design cycles applicable to the Class 1 components were assembled.

The actual frequency of occurrence for the fatigue sensitive design cycles was determined and compared to the design cycle set. The severity of the actual plant cycles was also compared to the severity of the design cycles. These comparisons were performed in order to demonstrate that on an event-by-event basis the design cycle profiles envelope actual plant operation. In addition, a review of the applicable administrative and operating procedures was performed to verify the effectiveness of the Fatigue Monitoring Program. The reviews described above concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation.

The analyses associated with verifying the structural integrity of the Class 1 components have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

For license renewal, continuation of the Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. The Fatigue Monitoring Program is considered a confirmatory program.

### 18.3.2.2 ASME BOILER AND PRESSURE VESSEL CODE, SECTION III, CLASS 2 AND 3, AND ANSI B31.1 COMPONENTS

St. Lucie Unit 2 has a number of piping systems within the scope of license renewal that were designed to the requirements of ASME Section III, Class 2 and 3, or ANSI B31.1, "Power Piping." Piping systems designed to these requirements include a stress range reduction factor to provide conservatism in the design to account for cyclic conditions due to operations. The stress range reduction factor is 1.0 as long as the location does not exceed 7000 full temperature thermal cycles during its operation. This represents a condition where a piping system would have to be cycled approximately once every 3 days over the extended plant life of 60 years.

A review of ASME Section III, Class 2 and 3, and ANSI B31.1 piping within the scope of license renewal was undertaken in order to establish the cyclic operating practices of those systems that operate at elevated temperatures. Based on industry guidance, any piping system with operating temperatures less than 220°F (carbon steel) or 270°F (stainless steel) may be conservatively excluded from further consideration of thermal fatigue.

Under current plant operating practices, piping systems within the scope of license renewal are only occasionally subjected to cyclic operation. Typically these systems are subjected to continuous steady-state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or for periodic testing. The review of applicable plant systems determined that, except for the RCS hot-leg sample piping, components will not exceed 7000 equivalent full temperature thermal cycles during the period of extended operation. Therefore, the current piping analyses remain valid for the period of extended operation.

The RCS hot-leg sample lines could exceed the 7000 equivalent full temperature thermal cycles during the period of extended operation based on the current sampling practices. The sample piping and tubing were re-evaluated to consider the projected number of cycles and the analyses were found acceptable for the period of extended operation.

Except for the RCS hot-leg sample lines, the ASME Section III, Class 2 and 3, and ANSI B31.1 piping fatigue analyses within the scope of license renewal remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The RCS hot-leg sample lines' fatigue analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

### 18.3.2.3 ENVIRONMENTALLY ASSISTED FATIGUE

Generic Safety Issue (GSI) 190 was initiated by the NRC staff because of concerns about the potential effects of reactor water environments on RCS component fatigue life during the period of extended operation. The FPL approach to address reactor water environmental effects accomplishes two objectives. First, the TLAA on fatigue design has been resolved by confirming that the original transient design limits remain valid for the 60-year operating period. Confirmation by fatigue monitoring will ensure that these transient design limits are not exceeded. Second, reactor water environmental effects on fatigue life are examined using the most recent data from laboratory simulation of the reactor coolant environment.

As a part of the industry effort to address environmental effects for operating nuclear power plants during the current 40-year licensing term, Idaho National Engineering Laboratories (INEL) evaluated, in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995, fatigue-sensitive component locations at plants designed by all four U. S. nuclear steam supply system (NSSS) vendors. The pressurized water reactor (PWR) calculations included in NUREG/CR-6260, especially for the "Older Vintage Combustion Engineering Plant," match St. Lucie relatively closely with respect to design codes used, as well as the analytical approach and techniques used. In addition, the design cycles considered in the evaluation match or bound the St. Lucie Unit 2 design.

Environmental fatigue calculations have been performed for St. Lucie Unit 2 for those component locations included in NUREG/CR-6260 using the appropriate methods contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," March 1998, or NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999, as appropriate. Based on these results, all component locations were determined to be acceptable for the period of extended operation, with the exception of the pressurizer surge line (specifically the surge line elbow below the pressurizer).

FPL has selected aging management to address pressurizer surge line fatigue during the period of extended operation, in lieu of performing additional analyses to refine the fatigue usage factors. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be adequately managed during the extended period of operation by the continued performance of the St. Lucie ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program, as described in Subsection 18.2.2.1. Additionally, specific requirements will be included to evaluate pressurizer surge line flaws (if identified) with regard to environmentally assisted fatigue (see Subsection 18.2.2.1).

## 18.3.3 ENVIRONMENTAL QUALIFICATION

The thermal, radiation, and wear cycle aging analyses of plant electrical/I&C components have been identified as TLAAs for St. Lucie Unit 2. In particular, the environmental qualification evaluations of electrical equipment with a 40-year qualified life or greater have been determined to be TLAAs.

Equipment included in the St. Lucie Environmental Qualification Program has been evaluated to determine if existing environmental qualification aging analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated as it is for equipment currently qualified at St. Lucie for 40 years or less. When aging analysis cannot justify a qualified life into the license renewal period, then the component or parts will be replaced prior to exceeding their qualified lives in accordance with the Environmental Qualification Program, as described in Subsection 18.2.5.

Age-related service conditions that are applicable to the environmentally qualified equipment (i.e., 60 years of exposure versus 40 years) were evaluated for the period of extended operation to verify that the current environmental qualification analyses are bounding. The evaluations considered radiation, thermal, and wear cycle aging effects.

Therefore, the analyses associated with the environmental qualification of electrical equipment remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

### 18.3.4 CONTAINMENT PENETRATION FATIGUE

Containment penetration bellows are specified to withstand a lifetime total of 7000 cycles of expansion and compression due to maximum operating thermal expansion, and 200 cycles of other movements (seismic motion and differential settlement).

The containment penetrations are categorized as follows:

- Type I — Those which must accommodate considerable thermal movements (hot penetrations)
- Type II — Those which are not required to accommodate thermal movements (cold penetrations)
- Type III — Those which must accommodate moderate thermal movements (semi-hot penetrations)
- Type IV — Containment sump recirculation suction lines
- Type V — Fuel transfer tube

The containment penetration bellows fatigue analyses have been evaluated and determined to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

### 18.3.5 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A Leak-Before-Break (LBB) analysis was performed for Combustion Engineering designed Nuclear Steam Supply Systems (NSSS), which included St. Lucie Unit 2. The LBB analysis was performed to show that any potential leaks that develop in the RCS primary coolant loop piping can be detected by plant monitoring systems before a postulated crack causing the leak would grow to unstable proportions during the 40-year plant life. As documented in a March 5, 1993, NRC letter to FPL, the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie Units are bounded by the Combustion Engineering Owners Group analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie Units.

The aging effects that must be addressed during the period of extended operation include thermal aging of the primary loop piping components and fatigue crack growth. Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. The only significant thermal aging effect on the RCS loop piping is embrittlement of the duplex ferritic cast austenitic stainless steel (CASS) components. This effect results in a reduction in fracture toughness of the material.

A review concluded that the LBB analysis used conservative material toughness properties relative to correlations developed for fully aged cast stainless steel, which covers the extended period of operation. Therefore, the thermal aging assumptions used for the CASS piping do not satisfy one of the six criteria for a TLAA and no additional evaluation is required for the period of extended operation.

The LBB fatigue crack growth analysis assumes 40-year design cycles. The plant design cycles are is consistent with those utilized in the fatigue crack growth analysis and bound the period of extended operation. Fatigue crack growth for the period of extended operation is negligible.

The RCS primary loop piping LBB fatigue crack growth analysis has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

### 18.3.6 CRANE LOAD CYCLE LIMIT

The following cranes have load cycle assumptions that result in the fatigue analyses being TLAAs:

- Reactor Building Polar Crane
- Refueling Machine and Hoist
- Reactor Containment Building Auxiliary Telescoping Jib Crane
- Fuel Transfer Machine
- Spent Fuel Handling Machine
- Refueling Canal Bulkhead Monorail
- Cask Storage Pool Bulkhead Monorail
- Intake Structure Bridge Crane

(Note: The Fuel Cask Crane does not require a TLAA evaluation because the crane's lifting function is not in the scope of license renewal.)

The load cycles for these cranes were evaluated for the period of extended operation. For each crane, the actual usage over the projected life through the period of extended operation will be far less than the analyzed quantity of cycles. All the cranes in the scope of license renewal will continue to perform their intended function throughout the period of extended operation.

Therefore, the analyses associated with crane design, including fatigue, are valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

### 18.3.7 ALLOY 600 INSTRUMENT NOZZLE REPAIRS

Small diameter Alloy 600 nozzles, such as pressurizer and RCS hot-leg instrumentation nozzles in Combustion Engineering designed PWRs have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking. The residual stresses imposed by the partial-penetration "J" welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the "half nozzle" weld repair has been used to repair selected Alloy 600 instrument nozzles. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the "J" weld.

A fracture mechanics analysis was performed and submitted to the NRC to support the Unit 2 pressurizer steam space half nozzle repairs performed in 1994. The fracture mechanics analysis justified the acceptability of indications in the "J" weld based on a conservative postulated flaw size and flaw growth considering the applicable design cycles. The analysis concluded that the postulated flaw size in the instrument nozzle was acceptable for the remaining design life of the plant (30 years, or 75% of the original 40-year plant design life). Consequently, only 75% of the original design cycles was assumed in the flaw growth analysis. However, this analysis has been superseded by a subsequent analysis that considered 100% of the original design cycles, as discussed below.

A half nozzle repair was implemented on a Unit 1 RCS hot-leg instrumentation nozzle in April 2001. In response to NRC questions regarding this repair, FPL documented that the indications in the "J" weld were bounded by the fracture mechanics analysis provided in Combustion Engineering Owner's Group (CEOG) Topical Report CE NPSD-1198-P. FPL also documented in that response that the CEOG topical report is applicable to the Unit 2 pressurizer steam space nozzle repairs performed in 1994.

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. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the St. Lucie Unit 2 UFSAR. This generic analysis bounds the Class 1 fatigue design requirements of St. Lucie Unit 2. As discussed in Subsection 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.

The flaw growth analysis of the Unit 2 pressurizer steam space Alloy 600 instrument nozzle repairs has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

# APPENDIX B

## AGING MANAGEMENT PROGRAMS

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# 1.0 INTRODUCTION

The St. Lucie Units 1 and 2 Integrated Plant Assessment comprises four major activities, consistent with the NRC, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" [Reference B-1]. The first two activities, "Identification of Structures and Components that are Subject to Aging Management Review" and "Identification of Aging Effects Requiring Management," have been described in the body of this application. The remaining major activities, "Identification of Plant-Specific Programs That Will Manage the Identified Aging Effects Requiring Management" and "Aging Management Demonstration for Existing Programs," are described herein.

The St. Lucie programs described herein, with the exception of the Environmental Qualification Program and the Fatigue Monitoring Program, are credited for managing the effects of aging. The Environmental Qualification Program is credited for ensuring the qualified life of electrical and I&C components within the scope of 10 CFR 50.49 is maintained. The Fatigue Monitoring Program is credited for confirming that Reactor Coolant System design cycle assumptions remain valid. The programs described include both existing programs and new programs currently not being conducted.

Section 3.0 of this Appendix contains a description of each program that includes a statement that the program is either consistent with the GALL Report [Reference B-2], consistent with the GALL Report with exceptions, or it is a plant-specific program. Aging management programs provide reasonable assurance that the effects of aging will be adequately managed so that the structures and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation. The demonstrations, along with the program and activity descriptions, meet the requirements of 10 CFR 54.21(a)(3). Along with the technical information contained in the body of this application, this appendix is intended to allow the NRC to make the finding contained in 10 CFR 54.29(a)(1).

Commitment dates associated with the implementation of new programs and enhancements to existing programs are contained in Appendix A.

# 2.0 AGING MANAGEMENT PROGRAM ATTRIBUTES

The attributes that are used to describe aging management programs are discussed in this section. NEI 95-10 [Reference B-3], Sections 4.2 and 4.3, served as the primary input to the attribute definitions.

The St. Lucie aging management programs were compared to the aging management programs described in the GALL Report [Reference B-2]. For each program in Section 3.0 that has no corresponding GALL program, the attributes defined below are discussed and the program is identified as plant specific. For each program in Section 3.0 that was determined to be consistent with a GALL program, the GALL program reference is provided, and the only attribute discussed is "Operating Experience and Demonstration." For programs that are consistent with GALL, but for which clarification is required, the GALL program reference is provided and the clarifications are discussed in addition to the attribute "Operating Experience and Demonstration." Section 3.0 provides a listing of St. Lucie programs and identifies which ones are plant specific and which ones are consistent with GALL. The attribute information provided in Section 3.0 for plant-specific and GALL programs is consistent with the information provided to the NRC for the NEI License Renewal Demonstration Project [Reference B-4].

FPL has established and implemented a Quality Assurance Program to provide assurance that the design, procurement, modification, and operation of nuclear power plants conform to applicable regulatory requirements. The FPL Quality Assurance Program, described in the FPL Topical Quality Assurance Report, is in compliance with the requirements of 10 CFR 50, Appendix B. The FPL Quality Assurance Program meets the requirements provided by the NRC Regulatory Guidance and Industry Standards as listed in Appendix C of the FPL Topical Quality Assurance Report. For all aging management programs credited for license renewal, the program attributes of Corrective Actions, Confirmation, and Administrative Controls are performed or, in the case of new programs will be performed, in accordance with the FPL Quality Assurance Program, and will apply to all components and structural components within the scope of the programs, including non-safety related components and structural components.

The descriptions of the attributes for Corrective Actions and Administrative Controls are the same for all aging management programs credited for license renewal. Accordingly, discussions of Corrective Actions and Administrative Controls are not included in the summary descriptions of the individual programs in this appendix, but are presented below.

**Corrective Actions**

This attribute is a description of the action taken when the established acceptance criterion or standard is not met. This includes timely root-cause determination and prevention of recurrence, as appropriate.

**Administrative Controls**

This attribute is an identification of the plant administrative structure under which the programs are executed.

The FPL corrective action program is an existing and effective program for identifying, evaluating, and correcting deficiencies and is implemented in accordance with the Quality Assurance Program. Under the guidance of the FPL Quality Assurance Program, Quality Instructions and Administrative Procedures for corrective actions require that any deficiency documented by an individual shall be evaluated, dispositioned, and either corrected or declared acceptable in accordance with the deficiency disposition. These procedures and instructions provide guidance on documentation, evaluation, completion, and confirmation actions, including follow-up of corrective actions.

The remaining attribute definitions used to describe new and existing programs are:

**Scope**

This attribute is a clear statement of the reason why the program exists for license renewal.

**Preventive Actions**

This attribute is a description of preventive actions taken to mitigate the effects of the susceptible aging mechanisms and of the basis for the effectiveness of these actions.

**Parameters Monitored or Inspected**

This attribute is a description of parameters monitored or inspected, and how they relate to the degradation of the particular component or structure, and its intended function.

**Detection of Aging Effects**

This attribute is a description of the type of action or technique used to identify or manage the aging effects or relevant conditions.

**Monitoring and Trending**

This attribute is a description of the monitoring, inspection, or testing frequency, and sample size (if applicable).

**Acceptance Criteria**

This attribute is an identification of the acceptance criteria or standards for the relevant conditions to be monitored or the chosen examination methods.

**Confirmation Process**

This attribute is a description of the process to ensure that adequate corrective actions have been completed and are effective.

**Operating Experience and Demonstration**

This attribute is a summary of the operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs. Program demonstration is also included in this summary.

# 3.0 AGING MANAGEMENT PROGRAMS

The following programs are credited to manage the aging effects (except as noted in Section 1.0) for license renewal.

**New Aging Management Programs**

- Condensate Storage Tank Cross-connect Buried Piping Inspection (plant-specific program; Unit 1 only)
- Galvanic Corrosion Susceptibility Inspection Program (plant-specific program)
- Pipe Wall Thinning Inspection Program (plant-specific program)
- Reactor Vessel Internals Inspection Program (plant-specific program)
- Small Bore Class 1 Piping Inspection (plant-specific program)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (GALL program)

**Existing Aging Management Programs**

- Alloy 600 Inspection Program (plant-specific program)
- ASME Section XI Inservice Inspection Program
  - ➢ ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (GALL program)
  - ➢ ASME Section XI, Subsection IWE Inservice Inspection Program (GALL program)
  - ➢ ASME Section XI, Subsection IWF Inservice Inspection Program (GALL program)
- Boraflex Surveillance Program (GALL program; Unit 1 only)
- Boric Acid Wastage Surveillance Program (GALL program)
- Chemistry Control Program
  - ➢ Chemistry Control Program - Water Chemistry Control Subprogram (GALL program)
  - ➢ Chemistry Control Program - Closed-Cycle Cooling Water System Subprogram (GALL program)
  - ➢ Chemistry Control Program - Fuel Oil Chemistry Subprogram (plant-specific program)
- Environmental Qualification Program (GALL program)
- Fatigue Monitoring Program (plant-specific program)
- Fire Protection Program (plant-specific program)
- Flow Accelerated Corrosion Program (GALL program)
- Intake Cooling Water System Inspection Program (plant-specific program)
- Periodic Surveillance and Preventive Maintenance Program (plant-specific program)

- Reactor Vessel Integrity Program (plant-specific program)
- Steam Generator Integrity Program (GALL program)
- Systems and Structures Monitoring Program (plant-specific program)

Demonstration that each of the above programs adequately addresses the identified aging effect is in the following sections.

# 3.1 NEW AGING MANAGEMENT PROGRAMS

## 3.1.1 CONDENSATE STORAGE TANK CROSS-CONNECT BURIED PIPING INSPECTION (Unit 1 only)

As identified in Chapter 3, the Condensate Storage Tank Cross-connect Buried Pipe Inspection is credited for aging management of Auxiliary Feedwater and Condensate piping.

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program XI.M28, "Buried Piping and Tanks Surveillance," which is intended for carbon steel piping. The program cannot be applied to the condensate storage tank cross-connect because the pipe is stainless steel. Commitment dates associated with the implementation of this new program are contained in Appendix A.

**Scope**

The inspection provides for visual examination to detect loss of material. The scope of the inspections involves the external surfaces of buried condensate storage tank cross-connect pipe. This inspection is credited for managing the external loss of material due to pitting and microbiologically influenced corrosion.

**Preventive Actions**

There are no preventive actions applicable to this inspection.

**Parameters Monitored or Inspected**

The inspection will assess the extent of external corrosion of the condensate storage tank cross-connect piping based on surface conditions at a selected location. The location for inspection will be selected based on the worst-case condition for moisture. The examination will be performed to identify the potential effects of external loss of material due to pitting and microbiologically influenced corrosion.

**Detection of Aging Effects**

The aging effect of loss of material will be evident from visual inspection.

**Monitoring and Trending**

The one-time inspection will provide confirmatory information on the condition of the pipe. Because there is no operating history of degradation, a one-time inspection was selected. If significant loss of material is detected, the appropriate corrective action, including program revision if needed, will be implemented.

**Acceptance Criteria**

The results of the examinations will be evaluated in accordance with the minimum wall thickness requirements of the applicable design code (ANSI B31.1).

**Confirmation Process**

Follow-up inspections, if required, will be scheduled based upon actual corrosion rates or inspection findings, and documented in accordance with the corrective action program.

### Operating Experience and Demonstration

Visual inspection techniques have been used at St. Lucie Units 1 and 2 for many years. These techniques have proven successful at determining the extent of loss of material based on the surface conditions of piping/fittings and other components.

The Condensate Storage Tank Cross-connect Buried Piping Inspection is a new inspection that will use techniques with demonstrated capability and a proven industry record to assess external surface conditions of the buried portions of stainless steel. The examination will be performed utilizing approved plant procedures and qualified personnel. The examination techniques that will be used in this inspection have been previously used to assess piping condition in many other plant systems. Because there is no operating history of degradation, a one-time inspection was selected.

Based upon the above, the implementation of the Condensate Storage Tank Cross-connect Buried Piping Inspection will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.1.2 GALVANIC CORROSION SUSCEPTIBILITY INSPECTION PROGRAM

As identified in Chapter 3, the Galvanic Corrosion Susceptibility Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

| | |
|---|---|
| Auxiliary Feedwater and Condensate | Instrument Air |
| Component Cooling Water | Main Feedwater and Steam Generator Blowdown |
| Containment Cooling | Main Steam, Auxiliary Steam, and Turbine |
| Containment Spray | Primary Makeup Water |
| Diesel Generator and Support Systems | Safety Injection |
| Fire Protection | Turbine Cooling Water (Unit 1 only) |
| Fuel Pool Cooling | Ventilation |

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. Commitment dates associated with the implementation of this new program are contained in Appendix A.

### Scope

This program is credited for managing the potential loss of material due to galvanic corrosion on the surfaces of susceptible piping and components. Loss of material is expected mainly in carbon steel components directly coupled to stainless steel components in raw water systems, however, baseline examinations will be performed and evaluated to establish whether the corrosion mechanism is active in other systems. The program involves one-time inspections whose results will be utilized to determine the need for additional programmatic actions.

### Preventive Actions

Galvanic corrosion is caused by the presence of dissimilar metals in a conducting medium. Some components and systems utilize insulating flanges or cathodic protection as preventive measures to minimize galvanic interaction. The use of insulating flanges and cathodic protection performs a preventive function, but is not credited for elimination of galvanic corrosion.

### Parameters Monitored or Inspected

The program will assess the loss of material due to galvanic corrosion between dissimilar metals in locations determined to have the greatest susceptibility for this aging mechanism. The most limiting locations will be selected based on high galvanic potential, high cathode/anode area ratio, and high conductivity of the fluid in contact with the metals.

### Detection of Aging Effects

Visual inspections or volumetric examinations by qualified personnel will be utilized to address the extent of material loss. The aging effect, loss of material due to galvanic corrosion, will be evident by material loss at the location of the junction between the dissimilar metals.

**Monitoring and Trending**

Inspections will be conducted on a sampling basis. Locations selected for inspection will represent those with the greatest susceptibility for galvanic corrosion. Initial inspection results will be utilized to assess the need for expanded sample locations.

The program will utilize visual inspections or volumetric examinations to address the extent of the material loss. Plant experience with galvanic corrosion has been limited and typically has occurred in systems exposed to salt water. Examinations and inspections will be performed using approved procedures.

Inspection frequency will be determined based on the corrosion rate identified during the initial inspections. Instructions will be developed to assist in the determination of frequency and scope of future inspections.

**Acceptance Criteria**

The program consists of a confirmatory one-time inspection of piping to verify that loss of material due to galvanic corrosion is not occurring. In the event that significant loss of material is detected during the inspection, appropriate corrective actions will be established in accordance with the corrective action program. Evaluation of the inspection results will consider the minimum required wall thickness for the component consistent with the applicable design codes.

**Confirmation Process**

Follow-up inspections, if required, will be scheduled based upon inspection findings and documented in accordance with the corrective action program.

**Operating Experience and Demonstration**

The Galvanic Corrosion Susceptibility Inspection Program is a new program that will use techniques with demonstrated capability and a proven industry record to monitor material loss due to galvanic corrosion. This examination will be performed utilizing approved plant procedures and qualified personnel. The inspection techniques that will be used in this program have been used previously to monitor material condition for plant systems. This program will quantify the significance of this potential aging effect. This is a one-time inspection, because locations selected for inspection will represent those with the greatest susceptibility for galvanic corrosion. Initial inspection results will be utilized to assess the need for expanded sample locations.

There have been instances of galvanic corrosion at St. Lucie, primarily in the Intake Cooling Water System. Galvanic corrosion, for the Intake Cooling Water System, is managed using the Intake Cooling Water Inspection Program and Systems and Structures Monitoring Program. The bottom of the Unit 1 Refueling Water Tank, which is aluminum, developed a through-wall leak that was attributed to galvanic corrosion. Additionally, nozzles associated with the tank have experienced external galvanic corrosion at the flanges to the stainless steel piping due to water accumulation. Corrective actions for the tank included sealing the external tank bottom and lining the internal tank bottom with fiberglass-reinforced vinyl ester.

Corrective actions for the nozzles included removing the insulation or changing the insulation to sealed rubber. Since these modifications, no further instances of galvanic corrosion have occurred at these locations.

Based upon the above, the implementation of the Galvanic Corrosion Susceptibility Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.1.3 PIPE WALL THINNING INSPECTION PROGRAM

As identified in Chapter 3, the Pipe Wall Thinning Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Auxiliary Feedwater and Condensate

Component Cooling Water (Unit 2 only)

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. Commitment dates associated with the implementation of this new program are contained in Appendix A.

### Scope

The program provides for volumetric examination methods to detect loss of material by measuring wall thickness. The scope of the inspections involves examination of the Units 1 and 2 Auxiliary Feedwater stainless steel piping downstream of the recirculation orifices. The scope of this program also includes Unit 2 carbon steel control room air conditioning Component Cooling Water return piping. This inspection is credited for managing the internal loss of material due to erosion.

### Preventive Actions

No preventive actions are applicable to this inspection.

### Parameters Monitored or Inspected

The program will assess the extent of localized erosion of the internal surfaces of the Units 1 and 2 Auxiliary Feedwater stainless steel piping downstream of the recirculation orifices by measuring pipe wall thickness. The program also includes the Unit 2 carbon steel control room air conditioning Component Cooling Water return piping. This inspection is credited for managing the internal loss of material due to erosion.

### Detection of Aging Effects

The detection of loss of material will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing or radiography.

### Monitoring and Trending

This program involves periodic volumetric inspections. 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. The need for any replacements or change in examination frequency will be determined based on the results of each inspection, to ensure that the minimum wall thickness of the piping is maintained.

### Acceptance Criteria

The program consists of periodic inspections of piping to verify the extent of loss of material due to erosion. Evaluation of the inspection results will consider the minimum required wall thickness in accordance with ANSI B31.7 for Unit 1 Auxiliary Feedwater piping, and ASME Section III for Unit 2 Auxiliary Feedwater and Component Cooling Water piping.

### Confirmation Process

Follow-up inspections, if required, will be scheduled based upon inspection findings and documented in accordance with the corrective action program.

### Operating Experience and Demonstration

St. Lucie Units 1 and 2 have experienced pipe wall thinning due to erosion in the Auxiliary Feedwater recirculation lines and the Unit 2 control room air conditioning Component Cooling Water return lines. In lieu of design modifications to address high fluid velocity conditions, St. Lucie elected to periodically inspect the susceptible lines to manage loss of material. Volumetric inspection techniques have been used to in monitoring these lines. The examinations will be performed utilizing approved plant procedures and qualified personnel. The examination techniques that will be used in this inspection have been used previously to assess piping condition in many other plant systems.

Based upon the above, the implementation of the Pipe Wall Thinning Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.1.4 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

As identified in Chapter 3, the Reactor Vessel Internals Inspection Program is credited for aging management of the reactor vessel internals in the Reactor Coolant Systems.

This program is plant-specific. Although there are two reactor vessel internals aging management programs described in the GALL Report [Reference B-2], the St. Lucie program is integrated and cannot be compared directly.

The Reactor Vessel Internals Inspection Program will involve the combination of several activities culminating in the inspection of the St. Lucie Units 1 and 2 reactor vessel internals, once for each Unit, during the 20-year period of extended operation. The program is intended to supplement the reactor vessel internals inspections required by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Ongoing industry efforts are aimed at characterizing the aging effects associated with the reactor vessel internals. Further understanding of these aging effects will be developed by the industry over time and will provide additional bases for the inspections under this program. Pending results of industry progress with regard to validation of the significance of dimensional changes due to void swelling, the visual examinations described below may be supplemented to incorporate requirements for dimensional verification of critical reactor vessel internals parts.

FPL will submit an integrated report for St. Lucie Units 1 and 2 to the NRC prior to the end of the initial operating license term for St. Lucie Unit 1. This report will summarize the understanding of the aging effects applicable to the reactor vessel internals and will contain a description of the St. Lucie inspection plan, including methods for detection and sizing of cracks and acceptance criteria. Commitment dates associated with the implementation of this new program are contained in Appendix A.

**Scope**

This program manages the aging effects of cracking due to irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness due to irradiation and thermal embrittlement, and loss of mechanical closure integrity of bolted joints on accessible parts of the St. Lucie Units 1 and 2 reactor vessel internals. This program consists of VT-1, and in some cases enhanced VT-1, examinations that typically include remote visual inspections utilizing equipment such as television cameras, fiberoptic scopes, periscopes, etc. Other demonstrated acceptable inspection methods will be utilized for bolted joints, if deemed necessary.

The program also provides screening criteria to determine the susceptibility of cast austenitic stainless steel (CASS) parts to thermal embrittlement based on the casting method, molybdenum content, and percent ferrite.

**Preventive Actions**

There are no practical preventive actions available that will prevent IASCC, reduction in fracture toughness due to irradiation and thermal embrittlement, and loss of mechanical closure integrity of the reactor vessel internals bolted joints. However, to minimize the potential for stress corrosion cracking, the concentrations of chlorides, fluorides, and sulfates in the reactor coolant fluid are controlled by implementation of the Chemistry Control Program.

**Parameters Monitored or Inspected**

This examination monitors cracking and reduction in fracture toughness on the reactor vessel internals accessible parts, and loss of mechanical closure integrity of reactor vessel internals bolted joints.

**Detection of Aging Effects**

The aging effects of IASCC and reduction in fracture toughness due to irradiation and thermal embrittlement on selected reactor vessel internals parts will be detected by the performance of VT-1 examinations for the detection of cracks. Cracking is expected to initiate at the surface and will be detectable by the VT-1 visual examination.

Additionally, certain reactor vessel internals parts will be selected as leading locations for IASCC based on the highest projected combination of fluence and stress. For these parts, an enhanced VT-1 examination, capable of detecting 0.5 mil wire against a gray background, will be performed. If IASCC is identified by this inspection, accessible areas of additional reactor vessel internals parts potentially susceptible to IASCC will be inspected utilizing this enhanced VT-1 examination.

**Monitoring and Trending**

The VT-1, and in some cases enhanced VT-1, examinations of selected reactor vessel internals parts will be performed one time for each Unit during the period of extended operation. Based on the results of this examination additional examinations and/or repairs, if required, will be scheduled.

The inspections will correspond with ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program reactor vessel internals inspections. In order to develop a baseline for the extended period, FPL plans to perform the first of these reactor vessel internals inspections early in the renewal period on Unit 1, since it is expected to be the Unit leading in fluence at that time. Unless the Unit 1 inspection results dictate otherwise, the Unit 2 inspection will be conducted early in the second 10-year inspection interval in its license renewal term.

**Acceptance Criteria**

Acceptance criteria will be developed prior to the visual examination. Cracks will be evaluated for determination of the need and method of repair or replacement.

**Confirmation Process**

Any follow-up examination will be based on the evaluation of the initial examination results and will be documented in accordance with the corrective action program.

**Operating Experience and Demonstration**

The VT-1, and in some cases enhanced VT-1, examinations to be performed by this program are an inspection with demonstrated capability and a proven industry record to detect potential cracking. These examinations are performed utilizing approved plant procedures and qualified personnel. The remote visual examination proposed by this program utilizing equipment, such as television cameras, fiberoptic scopes, periscopes, etc., has been demonstrated previously as an effective method to detect cracking of reactor vessel internals parts. Similar visual examinations were successfully performed at St. Lucie Unit 1 during the core support barrel repair.

FPL participates in both the Westinghouse Owners Group (WOG) and the Combustion Engineering Owners Group (CEOG). There have been active programs in the WOG, particularly in the area of baffle/former bolting, and FPL has participated in these programs from the inception, including the Joint Owners Baffle Bolt (JOBB) program. Most of the current industry activities addressing aging effects on reactor vessel internals are being conducted under the EPRI Materials Reliability Project (MRP).

FPL has access to MRP products related to the reactor vessel as they are completed. The MRP strategy is to evaluate potential aging mechanisms and their effects on specific reactor vessel internals parts by evaluating causal parameters such as fluence, material properties, state of stress, etc. Critical locations can thereby be identified and tailored inspections can be conducted on either an integrated industry, NSSS, or plant-specific basis.

The following MRP projects are underway:

- Material testing of baffle/former bolts removed from the Point Beach, Farley, and Ginna nuclear power plants and determination of bolt operating parameters.
- Evaluation of the effects of irradiation, which include IASCC, swelling, and stress relaxation in PWRs.
- Evaluation of irradiated material properties.
- Void swelling "white paper" including available data and effects on reactor vessel internals.
- Development of a long-term reactor vessel internals aging management strategy.

Various tasks are addressed as JOBB program activities, which include a body of work to be performed by Electricite'de France. As these projects are completed, FPL will evaluate the results and factor them into the Reactor Vessel Internals Inspection Program, as applicable.

Based upon the above, implementation of the Reactor Vessel Internals Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.1.5 SMALL BORE CLASS 1 PIPING INSPECTION

As identified in Chapter 3, the Small Bore Class 1 Piping Inspection is credited for aging management of small bore Class 1 piping in the Reactor Coolant Systems.

The Small Bore Class 1 Piping Inspection will occur in the latter 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.

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. FPL will provide the NRC with a report describing the Small Bore Class 1 Piping Inspection plan prior to the implementation of this inspection. Commitment dates associated with the implementation of this new program are contained in Appendix A.

### Scope

The Small Bore Class 1 Piping Inspection will be a one-time volumetric examination of a sample of Class 1 piping less than 4 inches in diameter.

### Preventive Actions

No preventive actions are applicable to this inspection.

### Parameters Monitored or Inspected

The volumetric technique chosen will permit detection and sizing of cracking of small bore Class 1 piping.

### Detection of Aging Effects

The detection of cracking will be performed using approved and qualified volumetric examination techniques, such as ultrasonic testing or radiography.

### Monitoring and Trending

As noted above, this is a one-time inspection and, as such, no monitoring and trending are anticipated. The evaluation of the inspection results may result in additional examinations consistent with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The sample of welds to be examined will be selected by using a risk informed approach. The risk informed approach consists of 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.

### Acceptance Criteria

Any cracks identified will be evaluated and if appropriate, entered into the corrective action program.

### Confirmation Process

Any follow-up inspection required will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

### Operating Experience and Demonstration

This one-time inspection is a new activity that will use techniques with demonstrated capability and a proven industry record to detect piping weld and base material flaws. Approved and qualified volumetric examination techniques will be selected for use in performing this inspection. This inspection will be performed utilizing approved procedures and qualified personnel.

The Small Bore Class 1 Piping Inspection Program will incorporate results and recommendations from industry initiatives. For example, the current EPRI initiative to assemble guidance on non-destructive examination methodologies, and to provide recommendations and variables for specific non-destructive examination techniques will be incorporated in the St. Lucie Nuclear Plant program.

Based upon the above, the implementation of the Small Bore Class 1 Piping Inspection will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.1.6 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL PROGRAM

As identified in Chapter 3, the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program is credited for aging management of CASS Reactor Coolant System components.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program is consistent with the ten attributes of Aging Management Program XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," specified in the GALL Report [Reference B-2]. Commitment dates associated with the implementation of this new program are contained in Appendix A.

**Operating Experience and Demonstration**

The proposed Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program monitors the effects of reduction in fracture toughness on the intended function of the specific component by identifying the CASS materials that are susceptible to thermal aging embrittlement. For potentially susceptible materials, the program recommends either an enhanced volumetric examination to detect and size cracks, or a plant- or component-specific flaw tolerance evaluation. The proposed aging management program was developed using research data obtained on both laboratory-aged and service-aged materials.

Based upon the above, the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

# 3.2 EXISTING AGING MANAGEMENT PROGRAMS

## 3.2.1 ALLOY 600 INSPECTION PROGRAM

As identified in Chapter 3, the Alloy 600 Inspection Program is credited for aging management of the Reactor Coolant System.

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program X.M11, "Nickel-Alloy Nozzles and Penetrations," which applies primarily to the reactor vessel head penetrations. The St. Lucie program scope includes all Alloy 600 Reactor Coolant System pressure boundary components susceptible to PWSCC, some of which are not addressed in the GALL program. Also, the GALL program includes monitoring and examination activities that are included in separate programs at St. Lucie, i.e., Chemistry Control Program, Boric Acid Wastage Surveillance Program, and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Note that the Alloy 600 Inspection Program described below incorporates FPL's responses to NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Head Penetrations," and NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles."

As corrective actions to address PWSCC of Alloy 600 material, selected instrument nozzles have been replaced with Alloy 690 material which is not susceptible to PWSCC.

**Scope**

The Alloy 600 Inspection Program encompasses the St. Lucie Units 1 and 2 Alloy 600 Reactor Coolant System pressure boundary components including reactor vessel head penetration nozzles, reactor head vent pipes, pressurizer instrument nozzles and heater sleeves, piping instrument nozzles, steam generator primary side instrument nozzles, pressurizer spray pipe fittings, piping dissimilar metal welds, and Unit 2 control element drive mechanism motor housing lower end fittings. This program manages the aging effect of cracking due to PWSCC by utilizing the walkdown inspections, performed during every refueling outage, for visual inspection of the reactor vessel head external surfaces and all other susceptible leakage locations in the Reactor Coolant System as required by the Boric Acid Wastage Surveillance Program. The program also includes those reactor vessel head inspections to be performed in accordance with the St. Lucie commitments to NRC Generic Letter 97-01 and NRC Bulletin 2001-01 [References B-5 and B-6]. The scope and schedule of future reactor vessel head penetration inspection requirements is pending the issuance of industry guidance.

**Preventive Actions**

The program includes several PWSCC mitigation or preventive actions including:

- Nickel plating - this technique provides a barrier to the primary water and has been implemented on the Unit 1 pressurizer heater sleeves.
- Replacement of leaking Alloy 600 instrument nozzles with Alloy 690 material, which is not susceptible to PWSCC.

- Preventive replacement of selected pressurizer and Reactor Coolant System piping instrument nozzles with Alloy 690 material, which is not susceptible to PWSCC.

**Parameters Monitored or Inspected**

The program monitors the effect of PWSCC on the intended function of the affected components by detection of cracks and identification of reactor coolant leakage.

**Detection of Aging Effects**

A visual inspection of 100% of the Unit 1 and 2 reactor vessel heads, in accordance with the St. Lucie commitments to NRC Bulletin 2001-01, will be performed. The results of the inspection will be utilized to determine the need for additional bare metal visual or volumetric examinations.

Leak tests and walkdowns are used for detecting PWSCC of Alloy 600 components. The leak tests consist of visual inspections of each susceptible location in accordance with requirements of the existing Boric Acid Wastage Surveillance Program. Leakage is detected by steam discharge, borated water, or other evidence of fluid escape.

**Monitoring and Trending**

In response to NRC Bulletin 2001-01, the industry will develop a follow-up examination plan for reactor vessel head penetrations. The schedule and frequency for follow-up examinations will be determined based on the results of the initial examinations and pending industry guidance to be provided by the EPRI MRP and NEI. The visual inspections of the reactor vessel head area and other Reactor Coolant System Alloy 600 components are performed in accordance with the Boric Acid Wastage Surveillance Program.

**Acceptance Criteria**

The acceptance criteria for identified flaws will be developed using approved fracture mechanics methods, and industry- or plant-specific data. Evaluations would consider the stresses at the flaw location and industry developed crack propagation rates, if the flaw is to be left in service, prior to implementing any corrective action. The acceptance criterion for the visual inspections is no pressure boundary leakage.

**Confirmation Process**

For the Reactor Coolant System Alloy 600 pressure boundary components, confirmation will include inspection of the repaired/replaced component and pressure boundary integrity verification in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Additional testing/examinations will be performed, if required, by the corrective action program.

**Operating Experience and Demonstration**

St. Lucie has been an active participant in the CEOG, EPRI, and NEI initiatives regarding cracking of Alloy 600 Reactor Coolant System components. The Alloy 600 Inspection Program was created in response to NRC Generic Letter 97-01, and updated in response to NRC Bulletin 2001-01. This program has proven experience in addressing the concerns and requirements of the Generic Letter and the Bulletin. To date, St. Lucie has performed visual inspections on the top of the Units 1 and 2 reactor vessel heads for leakage as part of the Boric Acid Wastage Surveillance Program. No evidence of leakage from the Alloy 600 reactor vessel head penetrations has been identified.

Visual inspections performed at St. Lucie Units 1 and 2 have identified leakage of Alloy 600 pressurizer and Class 1 piping instrument nozzles. In all cases, the leaking nozzles have been removed and replaced in accordance with the requirements of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The visual inspections provided timely detection and repair of Reactor Coolant System pressure boundary leakage.

The St. Lucie Alloy 600 Inspection Program is based on the industry and St. Lucie responses to NRC Generic Letter 97-01 and NRC Bulletin 2001-01. This program utilizes analytical methods for prediction of cracking/propagation due to PWSCC and is validated by reactor vessel head penetration inspections performed by participating utilities.

Based upon the above, the implementation of the Alloy 600 Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.2 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

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

As identified in Chapter 3, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Reactor Coolant

Containment Spray

The currently applicable ASME code years for the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program are identified in FPL Letter L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7] and FPL Letter L-93-191, dated August 4, 1993, for Unit 2 [Reference B-8]. The program is consistent with the ten attributes of Aging Management Program XI.M1, "ASME Section XI Inservice Inspections, Subsections IWB, IWC and IWD," specified in the GALL Report [Reference B-2], with the following clarification. This program credits ASME Code Case N-509 [Reference B-9], which allows alternate examination categories for certain integrally welded attachments and has been approved for use at St. Lucie. Although ASME Section XI, Subsection IWD is included in the scope of this program, this application does not credit Subsection IWD for managing the effects of aging. In addition, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will be enhanced to require evaluation of surge line flaws (if identified) with regard to environmentally assisted fatigue and to require VT-1 inspections of the core stabilizing lugs and core support lugs. Commitment dates associated with the enhancements to this program are contained in Appendix A.

**Operating Experience and Demonstration**

ASME Section XI provides the rules and requirements for inservice inspection, testing, repair, and replacement of Class 1, 2, and 3 components. It has been shown to be generally effective in managing the aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants. Components are chosen for inspection in accordance with the requirements of Subsections IWB, IWC, and IWD, and are inspected using volumetric, surface, or visual examination methods.

The inservice inspection of Class 1, 2, and 3 components and piping has been conducted since initial plant startup as required by Technical Specifications and 10 CFR 50.55a. These inspections have been documented and evaluated, and degraded conditions have been corrected.

Implementation of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program at St. Lucie currently includes examinations of Class 1, 2 and 3 components over a ten-year interval. For Class 1 piping, the examinations have yielded only indications of surface anomalies and surface geometry with no indication of cracking. For Class 2 piping, FPL is monitoring a flaw on a Unit 2 Safety Injection line consistent with applicable code requirements.

Based upon the above, the implementation of the enhanced ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

### 3.2.2.2 ASME SECTION XI, SUBSECTION IWE INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the ASME Section XI, Subsection IWE Inservice Inspection Program is credited for aging management of specific structural component/commodity groups in the Containments.

The ASME Section XI, Subsection IWE Inservice Inspection Program is consistent with the ten attributes of Aging Management Programs XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J," specified in the GALL Report [Reference B-2]. For St. Lucie Units 1 and 2, leak rate testing in accordance with 10 CFR 50, Appendix J, is included as Category E-P in the ASME Section XI, Subsection IWE Inservice Inspection Program. The currently applicable ASME code years for the ASME Section XI, Subsection IWE Inservice Inspection Program are identified in FPL Letters L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7], and L-2000-227, dated November 13, 2000, for Unit 2 [Reference B-10].

**Operating Experience and Demonstration**

As stated in Subsection 3.5.1.1.1, the codes and standards used for the design and fabrication of the St. Lucie Containments are identified in Unit 1 UFSAR Section 3.8 and Unit 2 UFSAR Section 3.8. ASME Section XI, Subsection IWE was incorporated by reference into 10 CFR 50.55a, and accordingly, St. Lucie ASME Section XI, Subsection IWE Inservice Inspection Program was developed and implemented.

Containment leak-tight verification and visual examination of the steel components that are part of the leak-tight barrier have been conducted at St. Lucie since initial startup. Prior to the development of the ASME Section XI, Subsection IWE Inservice Inspection Program, visual examinations were performed in accordance with 10 CFR 50, Appendix J. Although the visual inspection is general in nature, it is intended to detect areas of widespread flaking, rust, pitting, gouges, and cracks or other visible indications on welds or structural elements. Detailed inspections and evaluations are performed as warranted if gross discrepancies are detected. Conditions noted during the inspection of the Containment are documented on inspection reports. An evaluation of inaccessible areas is performed when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

A review of the plant-specific operating experience determined that there were no significant degradations associated with the Containment vessels. The operating history identified included the following:

- Degraded coatings without corrosion were observed on several Unit 1 electrical penetrations.
- Missing coatings were identified on the Unit 1 Containment dome.

- Pitting was observed on the Unit 2 Containment vessel exterior in the vicinity of the annulus floor. The maximum depth was analyzed and determined to be acceptable. The affected area was coated and follow-up inspections were performed.
- The Unit 2 Containment personnel airlock outer door handwheel shaft seal failed during the semi-annual strongback test. The cause was determined to be mis-alignment, and therefore, not age related.
- Cracking of the moisture barrier between the steel Containment vessel and the concrete floor was observed on Unit 2. Sealant material was removed and the Containment vessel was inspected. Minor corrosion was observed, but no vessel repairs were required.
- Degraded coatings and minor corrosion were observed at a piping penetration on Unit 2. The area was cleaned and recoated in accordance with plant procedures.

Based upon the above, the continued implementation of the ASME Section XI, Subsection IWE Inservice Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

### 3.2.2.3 ASME SECTION XI, SUBSECTION IWF INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the ASME Section XI, Subsection IWF Inservice Inspection Program is credited for aging management of Class 1, 2, and 3 component supports in the following structures:

| | |
|---|---|
| Component Cooling Water Areas | Intake Structures |
| Condensate Storage Tank Enclosures | Reactor Auxiliary Buildings |
| Containments | Steam Trestle Areas |
| Diesel Oil Equipment Enclosures | Ultimate Heat Sink Dam |
| Emergency Diesel Generator Buildings | Yard Structures |
| Fuel Handling Buildings | |

The ASME Section XI, Subsection IWF Inservice Inspection Program is consistent with the ten attributes of Aging Management Program XI.S3, "ASME Section XI, Subsection IWF," specified in the GALL Report [Reference B-2]. The currently applicable ASME code years for the ASME Section XI, Subsection IWF Inservice Inspection Program are identified in FPL Letter L-98-14, dated February 2, 1998, for Unit 1 [Reference B-7], and FPL Letter L-93-191, dated August 4, 1993, for Unit 2 [Reference B-8].

**Operating Experience and Demonstration**

St. Lucie Technical Specifications and 10 CFR 50.55a require a program for the inspection of Class 1, 2, and 3 components (including supports). ASME Section XI provides the rules and requirements for inservice inspection, testing, repair, and replacement of Class 1, 2, and 3 component supports. The ASME Section XI, Subsection IWF Inservice Inspection Program applies to Class 1, 2, and 3 component supports (piping supports and supports other than piping supports).

The inservice inspection of the Class 1, 2, and 3 component supports has been conducted on both Units since plant initial start-up. The visual examinations of Class 1, 2, and 3 component supports look for deformations or structural degradations, corrosion, and other conditions that could affect the intended function of the support. Conditions noted during the inspection of component supports are documented on inspection reports.

Loss of material has been identified for numerous supports. Evaluations determined the loss of material was caused by general corrosion. The degraded supports were entered into the corrective action program, and repaired or replaced as appropriate.

Based upon the above, the continued implementation of the ASME Section XI, Subsection IWF Inservice Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

### 3.2.3 BORAFLEX SURVEILLANCE PROGRAM (Unit 1 only)

As identified in Chapter 3, the Boraflex Surveillance Program is credited for aging management of the spent fuel storage racks in the Unit 1 Fuel Handling Building.

The Boraflex Surveillance Program is consistent with the ten attributes of Aging Management Program XI.M22, "Boraflex Monitoring," specified in the GALL Report [Reference B-2]. Note that the GALL program discusses the aging effect of loss of boron carbide, whereas the St. Lucie program discusses the equivalent aging effect change in material properties for the neutron absorbing material. The Boraflex Surveillance Program will be enhanced to include areal density testing. Commitment dates associated with the enhancement to this program are contained in Appendix A.

**Operating Experience and Demonstration**

St. Lucie Unit 1 initiated a blackness testing program following installation of high density spent fuel storage racks. The blackness testing has provided sufficient reliable data on the presence of Boraflex for use in criticality calculations to maintain the required 5% subcriticality margin for the five-year period of each test. The FPL response to NRC Generic Letter 96-04 [Reference B-11] assessed the capability of the Boraflex to maintain a 5% subcriticality margin and provided remedies for long-term Boraflex degradation.

The Boraflex Surveillance Program will be enhanced to include areal density testing. Areal density testing can provide a more accurate measurement of the degree of degradation of the Boraflex. Areal density testing has also been used successfully at various other nuclear power facilities, including FPL's Turkey Point Unit 3.

Based upon the above, the implementation of the enhanced Boraflex Surveillance Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Unit 1 CLB for the period of extended operation.

### 3.2.4 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

As identified in Chapter 3, the Boric Acid Wastage Surveillance Program is credited for aging management of specific cast iron, carbon steel, and low alloy steel component/ commodity groups, including adjacent structures, systems, and components, in the following systems and structures:

Systems

| | |
|---|---|
| Chemical and Volume Control | Main Feedwater and Steam Generator Blowdown |
| Component Cooling Water | Main Steam, Auxiliary Steam, and Turbine |
| Containment Cooling | Miscellaneous Bulk Gas Supply |
| Containment Isolation | Primary Makeup Water |
| Containment Post Accident Monitoring | Reactor Coolant |
| Containment Spray | Safety Injection |
| Fire Protection | Sampling |
| Fuel Pool Cooling | Service Water |
| Instrument Air | Ventilation |
| Intake Cooling Water | Waste Management |

Structures

| | |
|---|---|
| Containments | Fuel Handling Buildings |
| Reactor Auxiliary Buildings | Yard Structures |

The Boric Acid Wastage Surveillance Program is consistent with the ten attributes of Aging Management Program XI.M10, "Boric Acid Corrosion," specified in the GALL Report [Reference B-2]. In addition, St. Lucie credits this program for monitoring borated water systems for leakage that could potentially affect systems and components credited with a license renewal intended function, whereas the GALL program is limited to the Reactor Coolant System pressure boundary. The program will be enhanced to include portions of the Waste Management System within the scope of license renewal and to inspect and evaluate adjacent structures, systems, and components when leakage is identified. Commitment dates associated with enhancements to this program are contained in Appendix A.

**Operating Experience and Demonstration**

The Boric Acid Wastage Surveillance Program has been an ongoing program at St. Lucie since the 1980s. The program was implemented as a result of boric acid leaks experienced at St. Lucie and NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." This program addressed the Generic Letter program requirements including: (1) the determination of the principal locations where coolant leaks smaller than allowable Technical Specification limits could cause degradation of the pressure boundary, (2) methods for conducting examinations that are integrated into ASME Code VT-2 inspections conducted during system pressure tests, and (3) corrective actions to prevent recurrences of this type of leakage. The conservative philosophy established within the program has been successful in managing loss of material due to boric acid corrosion. It has provided for the timely identification of leakage and implementation of corrective actions as evidenced by work orders and condition reports. Since establishing this program, there have been no instances of boric acid corrosion that have impacted license renewal system intended functions.

Based upon the above, the implementation of the enhanced Boric Acid Wastage Surveillance Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.5 CHEMISTRY CONTROL PROGRAM

As identified in Chapter 3, the Chemistry Control Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Systems

| | |
|---|---|
| Auxiliary Feedwater and Condensate | Main Feedwater and Steam Generator Blowdown |
| Chemical and Volume Control | Main Steam, Auxiliary Steam, and Turbine |
| Component Cooling Water | Primary Makeup Water |
| Containment Cooling | Reactor Coolant |
| Containment Spray | Safety Injection |
| Demineralized Makeup Water (Unit 2 only) | Sampling |
| Diesel Generator and Support Systems | Turbine Cooling Water (Unit 1 only) |
| Fuel Pool Cooling | Ventilation |
| Instrument Air | |

Structures (Structural components exposed to fluids)

| | |
|---|---|
| Containments | Fuel Handling Buildings |

The GALL Report [Reference B-2] contains three aging management programs addressed by the St. Lucie Chemistry Control Program. The GALL programs are: XI.M2, "Water Chemistry," XI.M21, "Closed-Cycle Cooling Water System," and XI.M30, "Fuel Oil Chemistry." A discussion of each of these programs relative to the comparable subprogram in the St. Lucie Chemistry Control Program is provided below.

### 3.2.5.1 CHEMISTRY CONTROL PROGRAM - WATER CHEMISTRY CONTROL SUBPROGRAM

The Water Chemistry Control Subprogram is consistent with the ten attributes of the Aging Management Program XI.M2, "Water Chemistry" in the GALL Report, except as noted. This subprogram was developed in accordance with the guidance in EPRI TR-105714, "PWR Primary Water Chemistry Guideline" [Reference B-12] and EPRI TR-102134, "PWR Secondary Water Chemistry Guideline" [Reference B-13]. The GALL program credits inspection of select components to verify the effectiveness 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.

**Operating Experience and Demonstration**

The Chemistry Control Program - Water Chemistry Control Subprogram has been an ongoing program at St. Lucie since initial unit start-up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations, with technical input and concurrence from the U.S. NSSS vendors, as well as utility and water treatment experts.

The subprogram provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished through effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. Furthermore, the chemistry analyses are governed by the plant Quality Assurance Program to assure accurate results. Chemistry data is also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions that might adversely affect component intended functions.

No special one-time inspections for the purpose of verifying the effectiveness of the Water Chemistry Control Subprogram are required for St. Lucie. Internal surfaces of components are visually inspected for loss of material and other aging effects during routine and corrective maintenance requiring equipment disassembly. If adverse conditions are identified, corrective action is taken via the corrective action program, which includes cause determination. In cases where the aging mechanism is not readily apparent, metallurgical analyses are typically performed. Review of numerous metallurgical reports for the systems and structures listed above, identified no instances of crevice corrosion or Chemistry Program related concerns.

Based upon the above, the continued implementation of the Chemistry Control Program - Water Chemistry Control Subprogram will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

### 3.2.5.2 CHEMISTRY CONTROL PROGRAM - CLOSED-CYCLE COOLING WATER SYSTEM CHEMISTRY SUBPROGRAM

The Closed-Cycle Cooling Water System Chemistry Subprogram is consistent with the ten attributes of the Aging Management Program XI.M21, "Closed-Cycle Cooling Water System," in the GALL Report, except that this subprogram does not address surveillance testing and inspection. This subprogram was developed in accordance with the guidance in EPRI TR-107396, "Closed Cooling Water Chemistry Guideline" [Reference B-14]. The Intake Cooling Water Inspection Program implements the applicable surveillance testing and inspection aspects of the GALL program.

**Operating Experience and Demonstration**

The Chemistry Control Program - Closed-Cycle Cooling Water System Chemistry Subprogram has been an ongoing program at St. Lucie since initial unit start-up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations, with technical input and concurrence from utility and water treatment experts.

The subprogram provides assurance that the fluid environment to which piping and associated components are exposed will minimize corrosion. This is accomplished through effective monitoring of key parameters at established frequencies with well-defined acceptance criteria. Furthermore, the chemistry analyses are governed by the FPL Quality

Assurance Program to assure accurate results. Chemistry data is also monitored for trends that might be indicative of an underlying operational problem. This will provide for early detection of any conditions that might adversely affect component intended functions.

Based upon the above, the continued implementation of the Chemistry Control Program - Closed-Cycle Cooling Water System Chemistry Subprogram will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

### 3.2.5.3 CHEMISTRY CONTROL PROGRAM - FUEL OIL CHEMISTRY SUBPROGRAM

This subprogram is plant-specific. The Chemistry Control Program - Fuel Oil Chemistry Subprogram addresses properties of new and stored fuel. This subprogram was developed in accordance with the guidance in ASTM D975-81, "Standard Specification for Fuel Oil." The Aging Management Program XI.M30, "Fuel Oil Chemistry," in the GALL Report contains additional aspects such as water removal and internal tank inspection. For St. Lucie Units 1 and 2, these aspects are performed as part of the Periodic Surveillance and Preventive Maintenance Program. The attributes for the Fuel Oil Chemistry Subprogram are provided below.

**Scope of Program**

The Chemistry Control Program - Fuel Oil Chemistry Subprogram is focused on managing the conditions that cause loss of material of diesel fuel oil system component internal surfaces. The subprogram serves to reduce the potential of exposure of the internal surfaces to fuel oil contaminated with water and microbiological organisms.

**Preventive Actions**

The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of the diesel fuel oil storage tanks and periodic draining of water collected at the bottom of the fuel oil storage and day tanks minimizes the amount of water and the length of contact time. Tank inspection and water removal are performed as part of the Periodic Surveillance and Preventive Maintenance Program. These measures are effective in mitigating internal corrosion.

**Parameters Monitored or Inspected**

The parameters monitored by the Chemistry Control Program - Fuel Oil Chemistry Subprogram are in accordance with ASTM Standards D4057-81, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" for guidance on oil sampling and D2276-83, "Particulate Contamination in Aviation Turbine Fuels," Method A or Annex A-2 for determination of particulates. Other ASTM standards are utilized for fuel oil testing as specified in the St. Lucie Units 1 and 2 Technical Specifications.

**Detection of Aging Effects**

Degradation of the diesel fuel oil system components cannot occur without exposure to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with applicable diesel fuel oil standards and periodic sampling in accordance with the Technical Specifications provide assurance that fuel oil contaminants are below acceptable levels.

**Monitoring and Trending**

Water and particulate contamination concentrations are monitored and trended. Based on the St. Lucie Units 1 and 2 Technical Specifications, monthly sampling and analysis of fuel oil chemistry is performed.

**Acceptance Criteria**

The acceptance criteria for the chemistry parameters required to be monitored and controlled are listed in the St. Lucie Units 1 and 2 Technical Specifications and the Chemistry Control Program implementing procedures.

**Confirmation Process**

Follow-up testing is performed to confirm satisfactory completion of corrective actions. These actions are documented in accordance with the corrective action program.

**Operating Experience**

The Chemistry Control Program - Fuel Oil Chemistry Subprogram has been an ongoing program at St. Lucie since initial unit start-up and has evolved over many years of plant operation. The subprogram incorporates the best practices recommended by industry organizations.

The operating experience at St. Lucie Nuclear Plant has included particulate contamination due to a contaminated tanker truck transfer pump and hose. However, no instances of fuel oil system component failures attributed to contamination have been identified.

Based upon the above, the continued implementation of the Chemistry Control Program - Fuel Oil Chemistry Subprogram will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.6 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification Program is credited for ensuring the qualified life of electrical and I&C components within the scope of 10 CFR 50.49 (see Sections 2.5, 3.6, and 4.4 of this application).

Although not credited as an aging management program, the St. Lucie Environmental Qualification Program is consistent with the ten attributes of the Aging Management Program X.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in the GALL Report [Reference B-2]. The Environmental Qualification Program establishes the aging limit (qualified life) for each installed environmentally qualified device. The program ensures that the appropriate actions (repair, replacement, or refurbishment) are completed prior to a device exceeding its qualified life.

Environmental qualification evaluations are considered TLAAs for St. Lucie Units 1 and 2. The evaluations of these TLAAs are considered the technical rationale that the St. Lucie Units 1 and 2 CLBs will be maintained during the period of extended operation. Consistent with the NRC guidance for GSI-168, "Environmental Qualification of Electrical Components," no additional information is required to address this issue. In addition, no changes in activation energy were used in the TLAA evaluations performed.

**Operating Experience and Demonstration**

The Environmental Qualification Program is an ongoing program at St. Lucie that considers the best practices of industry organizations, vendors, and utilities. The program provides assurance that the environments to which installed devices are exposed will not exceed the qualified lives associated with the devices. This is accomplished through effective monitoring of key parameters (temperature and radiation) at established frequencies with well-defined acceptance criteria. The Environmental Qualification Program is governed by the FPL Quality Assurance Program to assure the requirements of 10 CFR 50.49 are maintained.

The overall effectiveness of the Environmental Qualification Program is supported by the excellent operating experience for systems, structures, and components that are influenced by the program. The program has been subject to periodic internal and external assessment activities that help to maintain highly effective control and facilitate continuous improvement.

Based upon the above, the continued implementation of the Environmental Qualification Program will provide reasonable assurance that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.7 FATIGUE MONITORING PROGRAM

As identified in Subsection 4.3.1, the Fatigue Monitoring Program is a confirmatory program for fatigue of Class 1 components in the Reactor Coolant System.

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary." At St. Lucie Units 1 and 2, cracking due to fatigue has not been identified as an aging effect requiring management. As such, the Fatigue Monitoring Program is considered a confirmatory program to ensure the fatigue TLAA analytical assumptions remain valid for the period of extended operation. The cycle monitoring procedure will be enhanced to require administrative action should the actual cycle count reach 80% of any design cycle limit. Commitment dates associated with enhancements to this program are contained in Appendix A.

### Scope

The Fatigue Monitoring Program is designed to track design cycle occurrences to ensure the Reactor Coolant System components remain within their design fatigue usage limits. The specific fatigue analyses validated by this monitoring program are associated with the reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and Class 1 Reactor Coolant System piping.

### Preventive Actions

The Fatigue Monitoring Program utilizes the systematic counting of design cycles to ensure that component design fatigue usage limits are not exceeded.

### Parameters Monitored or Inspected

The design cycles monitored by the Fatigue Monitoring Program for the purposes of confirmation of Class 1 fatigue analyses are the fatigue-sensitive design cycles assumed in the Reactor Coolant System component design analyses. Additional design cycles are monitored as required by the plant Technical Specifications.

### Detection of Aging Effects

The Fatigue Monitoring Program assures that the component design fatigue usage limits are not exceeded.

### Monitoring and Trending

An administrative procedure provides the methodology for counting design cycles. The procedure will be enhanced to provide guidance as design cycle limits are approached.

### Acceptance Criteria

The allowable number of design cycles are specified in the plant cycle monitoring procedure.

### Confirmation Process

To prevent exceeding fatigue design limits, the cycle monitoring procedure will be enhanced to require administrative action as described in Subsection 4.3.1 should the actual cycle count reach 80% of any design cycle limit.

### Operating Experience and Demonstration

The Fatigue Monitoring Program has been an ongoing program at St. Lucie since 1982, and has evolved over the many years of plant operation. As demonstrated in Subsection 4.3.1, the number of design cycles considered in the St. Lucie Units 1 and 2 CLBs fatigue analyses is sufficiently conservative to account for not only the current licensed term, but the extended period of operation as well. Confirmation will be accomplished through the Fatigue Monitoring Program.

The overall effectiveness of the Fatigue Monitoring Program is supported by independent review of the implementation and attributes of the program. A detailed review conducted by an outside organization, concluded the cycle monitoring procedure accurately identifies and classifies required Technical Specification and fatigue-sensitive design cycles, and provides an effective and consistent method for categorizing, counting, and tracking design cycles. The review concluded the program maintains sufficient information for each design cycle. In addition, a review of the design cycle counts documented to date was performed. Plant historical records were reviewed and compared against accumulated design cycle counts included in the administrative procedure. The review concluded that the accumulated design cycles documented conservatively reflect past plant operation.

Based upon the above, the continued implementation of the Fatigue Monitoring Program will provide reasonable assurance that the Reactor Coolant System components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.8 FIRE PROTECTION PROGRAM

As identified in Chapter 3, the Fire Protection Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Fire Protection System

Fire Rated Assemblies

This program is plant-specific. The GALL Report [Reference B-2] contains two programs, XI.M26, "Fire Protection," and XI.M27, "Fire Water System." The St. Lucie Fire Protection Program combines the appropriate scope of the two GALL programs. In addition, FPL credits the Systems and Structures Monitoring Program, the Galvanic Corrosion Susceptibility Inspection Program, and the Boric Acid Wastage Surveillance Program for managing aging of the appropriate components of the Fire Protection System and Fire Rated Assemblies. Concrete and steel structural components that serve as fire barriers are addressed with their associated structure, as appropriate.

**Scope**

The Fire Protection Program is credited for managing the aging effects of loss of material due to corrosion (including selective leaching) for the mechanical components of the Fire Protection System within the scope of license renewal. The mechanical components include valves (bodies only) and pumps (casings only), tanks, orifices, filters, piping, tubing, sprinkler heads, flexible hoses, halon system components, fire hydrants, vortex breakers, and sight glasses. This program is also credited for managing loss of material due to corrosion for fire doors.

**Preventive Actions**

Mechanical Fire Protection System components are periodically flushed, performance tested, and inspected. Many Fire Protection System components are provided with a protective coating to minimize the potential for external degradation. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited for eliminating aging effects.

**Parameters Monitored or Inspected**

Surface conditions are monitored visually to determine the extent of external material degradation. Visual examination will detect loss of material. 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.

**Detection of Aging Effects**

The detection of age-related degradation on external surfaces is determined by visual examination. Surfaces of components and structures are examined for coating degradation, rust, damage, deterioration, leakage, or corrosion. Functional testing and flushing of the systems clears away internal scale and corrosion products that could lead to blockage or obstruction of the system. Flow and pressure tests verify system integrity. Visual examinations of internal portions of the system, when opened, also verify unobstructed flow and integrity of the piping and components.

**Monitoring and Trending**

Administrative procedures contain the regulatory commitments and surveillance requirements for the Fire Protection Program. The procedures governed by the Fire Protection Program require various testing, inspection, or surveillance frequencies. The frequency and scope of the testing, inspection, or surveillance associated with the Fire Protection Program is sufficient to identify effects of aging prior to compromising the integrity of the system or its intended function.

**Acceptance Criteria**

The results of the testing, inspection, or surveillance will be evaluated in accordance with the acceptance criteria in the appropriate fire protection procedure(s). Degradation found as a result of the testing, inspection, or surveillance of the systems or components is entered into the corrective action program.

**Confirmation Process**

Administrative procedures require verification that the affected fire protection feature be restored to normal configuration and that post maintenance testing, if required, be performed prior to return to service.

**Operating Experience and Demonstration**

The Fire Protection Program has been an ongoing program at St. Lucie Units 1 and 2. This program was enhanced by implementation of 10 CFR 50, Appendix R, and has evolved over many years of plant operation. The program incorporates the best practices recommended by the National Fire Protection Association (NFPA) and Nuclear Electric Insurance Limited (NEIL) and is approved by the NRC. The Fire Protection Program has been significantly enhanced since initial plant operation and has been effective at maintaining fire protection features by reliable performance.

The overall effectiveness of the Fire Protection Program is demonstrated by the excellent operating experience of systems, structures, and components that are influenced by the Fire Protection Program. The Fire Protection Program has been subject to periodic internal assessment activities. These activities, as well as other external assessments, help to maintain highly effective fire protection control, and facilitate continuous improvement through monitoring industry initiatives and trends in the area of aging management.

Based upon the above, the continued implementation of the Fire Protection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

### 3.2.9 FLOW ACCELERATED CORROSION PROGRAM

As identified in Chapter 3, the Flow Accelerated Corrosion Program is credited for aging management of selected components/commodity groups in the following systems:

Main Steam, Auxiliary Steam, and Turbine

Main Feedwater and Steam Generator Blowdown

Reactor Coolant (steam generator nozzles)

The current program is consistent with the ten attributes of the Aging Management Program XI.M17, "Flow-Accelerated Corrosion," specified in the GALL Report [Reference B-2]. This program is implemented in accordance with the EPRI guidelines provided in NSAC-202L-R2, Recommendations for an Effective Flow Accelerated Corrosion Program" [Reference B-15]. In addition, based on the aging management reviews performed, the St. Lucie program scope will be enhanced to include small bore piping associated with selected steam traps and drain lines that are potentially susceptible to flow accelerated corrosion and external general corrosion. Commitment dates associated with the enhancement to this program are contained in Appendix A.

**Operating Experience and Demonstration**

Wall thinning problems in single-phase systems have occurred in Main Feedwater and Condensate Systems and in two-phase piping in extraction steam lines and moisture separation reheater and feedwater heater drain lines. The Flow Accelerated Corrosion Program has been an ongoing formalized program at St. Lucie since the 1980s. The program was originally implemented as a result of steam leaks experienced throughout the industry, including FPL sites. This program was formalized in response to Generic Letter 89-09, "Flow Accelerated Corrosion of Carbon Steel Pressure Boundary Components in PWR Plants." The Flow Accelerated Corrosion Program is continually upgraded based on industry experience and research.

The conservative philosophy established with the program has been successful in managing the loss of material due to flow accelerated corrosion. Various sections of susceptible piping are periodically examined using non-destructive examination techniques to determine the effects of flow accelerated corrosion. Results are evaluated and piping is either repaired or replaced as required. Branch connections are examined as St. Lucie or industry experience warrants.

Condition reports have been generated to document the results of ultrasonic examinations that identified piping wall thicknesses below the established screening criteria developed by the Flow Accelerated Corrosion Program. These condition reports resulted in repair, replacement, or subsequent inspection of the piping. Since 1996, there have been a small number of component replacements due to flow accelerated corrosion in the systems listed above. These include various Main Steam small bore and steam trap piping components and Steam Generator Blowdown piping components on Unit 1, and Steam Generator Blowdown System piping components on Unit 2.

Based upon the above, the implementation of the enhanced Flow Accelerated Corrosion Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.10 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

As identified in Chapter 3, the Intake Cooling Water Inspection Program is credited for aging management of specific component/commodity groups in the following systems:

Intake Cooling Water

Component Cooling Water

This program is plant-specific, although certain aspects of the Intake Cooling Water Inspection Program are comparable to Aging Management Program XI.M20, "Open-Cycle Cooling Water System," in the GALL Report [Reference B-2]. FPL credits the Intake Cooling Water System Inspection Program, Systems and Structures Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Boric Acid Wastage Surveillance Program for managing aging of Intake Cooling Water and Component Cooling Water components at St. Lucie Units 1 and 2.

**Scope**

The Intake Cooling Water System Inspection Program addresses the aging effects of loss of material due to various corrosion mechanisms, and biological and particulate fouling. It also addresses internal inspection of the Intake Cooling Water piping to identify and manage loss of material on the external surface of buried piping. The program utilizes differential pressure performance evaluations, systematic inspections, and corrective actions to ensure that loss of material or fouling does not lead to loss of intended functions of license renewal components. NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," requires the implementation of an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage caused by biological fouling, particulate fouling, corrosion, protective coating failures, and silting problems in systems and components supplied with Intake Cooling Water.

**Preventive Actions**

The Intake Cooling Water System Inspection Program is preventive in nature since it provides for the periodic inspection and maintenance of internal linings and coatings of piping and components exposed to aggressive cooling water environments. The program employs performance monitoring, testing, and periodic inspection and cleaning of heat exchangers, non-destructive examination of heat exchanger tubes, and backflushing and inspection of the Intake Cooling Water strainers. External coatings are applied to portions of the Intake Cooling Water System to minimize corrosion. However, coatings are not credited in the determination of aging effects requiring management.

**Parameters Monitored or Inspected**

Surface conditions of piping/components and their internal linings are visually inspected for degradation. Wall thickness measurements are taken when deemed necessary.

Pressures, temperatures, and flows associated with the Component Cooling Water heat exchangers are monitored during normal operation to verify heat transfer capability. Tube integrity of Component Cooling Water heat exchangers is monitored by periodic non-destructive examinations to ensure early detection of aging effects.

**Detection of Aging Effects**

Visual inspections of piping/components are performed to identify loss of material, fouling, damaged linings, and degraded material condition. Volumetric testing may be utilized to measure internal and external surface conditions and the extent of wall thinning based on the evaluation of the examination results.

Monitoring of the Component Cooling Water heat exchangers is conducted to provide for early identification of fouling and degraded conditions that could impact the ability of the Component Cooling Water heat exchangers to perform their intended function. Periodic tube inspections and cleaning are performed to assure heat exchanger performance and integrity.

**Monitoring and Trending**

Inspection scope, method, and testing frequencies are in accordance with FPL commitments under Generic Letter 89-13. Internal inspections of the Intake Cooling Water piping and components are normally performed during refueling outages on a scope and frequency based on past inspection results. As-found conditions are documented and repairs are made as required.

Monitoring of system parameters is used to provide an indication of flow blockage. Component Cooling Water heat exchanger tube condition is determined by eddy current testing and is documented accordingly. Heat exchanger tube cleaning, tube replacement, or other corrective actions are implemented as required.

**Acceptance Criteria**

Visual examinations of the internal surface of piping, fittings, heat exchangers, and basket strainers are performed to identify loss of material. When required, determination of wall thickness values is performed and evaluated.

Monitoring heat exchanger differential pressure, flow, and temperatures during normal operation ensures that the design basis heat transfer capability is maintained. Periodic backflushing removes the accumulation of biofouling agents, corrosion products, and silt. Biological and particulate materials not removed by backflushing are removed when the system is opened for cleaning and inspection.

**Confirmation Process**

Any required follow-up inspection will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

**Operating Experience and Demonstration**

The existing Intake Cooling Water System Inspection Program has been an ongoing formalized inspection program at St. Lucie since 1990. The program was formally implemented as a result of Generic Letter 89-13, which documented the need to implement monitoring of service water systems to ensure that they would perform their safety-related function. The conservative philosophy established within the program has been successful in managing the loss of material due to corrosion and fouling of the Component Cooling Water heat exchangers. Various sections of the Intake Cooling Water piping, basket strainers, and heat exchangers are periodically examined using visual examination to determine the effects of corrosion and fouling. Results are evaluated and components are either repaired or replaced as required. Branch connections are examined as plant/industry experience warrants.

Metallurgical analyses of Component Cooling Water heat exchanger tubes, performed in 1988 and 1991, indicated that erosion of aluminum brass tubes was caused by shells lodged in the tubes. Localized erosion caused small pinhole leaks in the tubes. To preclude erosion from occurring, the Component Cooling Water heat exchangers are opened periodically for cleaning and inspection.

A review of operating history for Intake Cooling Water and Component Cooling Water shows that the current aging management programs have supported system availability above its performance criteria for the period from May 1996 through June 2001. In addition, there have been no functional failures attributed to aging of pressure-retaining components during that period.

Based upon the above, the continued implementation of the Intake Cooling Water System Inspection Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.11 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

As identified in Chapter 3, the Periodic Surveillance and Preventive Maintenance Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Systems

| | |
|---|---|
| Chemical and Volume Control | Intake Cooling Water |
| Containment Cooling | Main Feedwater and Steam Generator Blowdown |
| Containment Spray | Primary Makeup Water |
| Diesel Generator and Support Systems | Service Water |
| Emergency Cooling Canal | Ventilation |
| Instrument Air | |

Structures

| | |
|---|---|
| Containments | Fuel Handling Buildings |
| Reactor Auxiliary Buildings | |

This program is plant-specific. There is no comparable aging management program in the GALL Report [Reference B-2]. The program will be enhanced to include inspections of components such as filter housings, radiator fins, flexible hoses, door seals, and expansion joints. Commitment dates associated with the enhancements to this program are contained in Appendix A.

**Scope**

The Periodic Surveillance and Preventive Maintenance Program is credited for managing the aging effects of loss of material, loss of seal, fouling (mechanical components only), and cracking for the component/commodity groups in the systems and structures listed above. The scope of the program provides for visual inspection and examination of surfaces of systems, structures, and components. Additionally, the program provides for replacement or refurbishment of certain components on a specified frequency, as appropriate, and periodic sampling and water removal from hydraulic accumulators and diesel fuel oil storage tanks.

**Preventive Actions**

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 based on operating experience.

**Parameters Monitored or Inspected**

Surface conditions of systems, structures, and components are monitored through visual examinations and leakage inspections to determine the existence of external and internal corrosion or deterioration. Flood protection features and weatherproofing are visually inspected to verify their material properties. Certain Intake Cooling Water components are replaced on a given frequency based on operating experience. Diesel generator fuel oil storage tanks are checked for water, and feedwater isolation valve hydraulic accumulators are sampled to detect water in the oil on a periodic basis.

**Detection of Aging Effects**

The aging effects of concern will be detected by visual inspection of surfaces for evidence of corrosion, cracking, leakage, debris, and deterioration, and by monitoring fuel oil and hydraulic oil for contamination. For some equipment, aging effects are managed by periodic replacement in lieu of inspection or refurbishment.

**Monitoring and Trending**

The inspections, replacements, and sampling activities associated with this program are performed on a specific frequency as listed in administrative procedures, and 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. Examples of inspections and activities included in the Periodic Surveillance and Preventive Maintenance Program are provided below:

- Inspection of diesel generator flexible hoses for cracking.
- Inspection for loss of seal of air tight door seals and gaskets.

The frequency of preventive maintenance tasks may be adjusted, as necessary, based on future plant-specific performance and/or industry experience.

**Acceptance Criteria**

Acceptance criteria and guidelines for the visual inspections are provided in the procedures and preventive maintenance tasks. Acceptance criteria are tailored for each individual inspection considering the aging effect being managed. Examples include:

- Inspections for loss of material provide guidance that require evaluation under the corrective action program if there is evidence of loss of material beyond uniform light surface corrosion.
- Visually detectable cracking requires evaluation under the corrective action program.
- Refurbishments and replacements are performed on a specified frequency based on plant experience or equipment supplier recommendations.

**Confirmation Process**

Any required follow-up inspection will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

**Operating Experience and Demonstration**

The Periodic Surveillance and Preventive Maintenance Program is an established program at St. Lucie. It utilizes as its bases various industry standards, including regulatory guidelines. The effectiveness and continuous improvement of the Periodic Surveillance and Preventive Maintenance Program is supported by the improved systems and structures material condition and reliability, documented by internal as well as external assessments during the last several years.

Based upon the above, the implementation of the enhanced Periodic Surveillance and Preventive Maintenance Program will provide reasonable assurance that the systems and components within the scope of license renewal will perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.12 REACTOR VESSEL INTEGRITY PROGRAM

As identified in Chapter 3, the Reactor Vessel Integrity Program is credited for aging management of the reactor vessels in the Reactor Coolant Systems.

This program is plant-specific. The Aging Management Program XI.M31, "Reactor Vessel Surveillances," in the GALL Report [Reference B-2] identifies in the Evaluation and Technical Basis section that reactor vessel surveillance programs are plant-specific and require further staff evaluation for license renewal.

The Reactor Vessel Integrity Program which manages reactor vessel irradiation embrittlement, encompasses the following subprograms:

- Reactor Vessel Surveillance Capsule Removal and Evaluation
- Fluence and Uncertainty Calculations
- Monitoring Effective Full Power Years
- Pressure-Temperature Limit Curves

Each subprogram described below.

The program documentation will be enhanced to generate a standard specification that documents all aspects of the Reactor Vessel Integrity Program. Commitment dates associated with the enhancement of this program are contained in Appendix A.

### 3.2.12.1 REACTOR VESSEL INTEGRITY PROGRAM - REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION SUBPROGRAM

The extended period of operation will require revision to the St. Lucie Units 1 and 2 surveillance capsule removal schedules. The information provided below is intended to satisfy the requirements of 10 CFR 50, Appendix H, for NRC review and approval of the revised surveillance capsule schedules.

The 40-year reactor vessel surveillance capsule removal schedules are presented in the current Unit 1 UFSAR Table 5.4-3 and Unit 2 UFSAR Table 5.3-9. These schedules provide for capsule removal when fluence levels can be obtained to predict the end of life (40 years) properties of the vessel beltline materials.

The requirements for new surveillance schedules are identified in 10 CFR 50, Appendix H. The method of determining the new surveillance schedules is outlined in Section XI.M31 of the GALL Report. The guidance indicates the program should follow ASTM E185, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2, and provide data for the reactor vessel materials with a fluence equivalent to 60 years.

The St. Lucie Unit 1 subprogram is a five capsule withdrawal schedule program, in accordance with ASTM E185-82.

The Unit 1 surveillance capsules contain base material from the lower shell plate and weld metal from the intermediate- to lower-shell girth weld. Three capsules have already been removed. The limiting vessel material is the lower shell axial weld, which is contained in the Beaver Valley Unit 1 surveillance program. This program has been evaluated and accepted by the NRC to be representative of the St. Lucie Unit 1 lower-shell axial weld seams [Reference B-16]. The Beaver Valley Unit 1 surveillance program has test data [Reference B-17] that bound the ¼T (one-quarter vessel thickness) fluence for the St. Lucie Unit 1 limiting weld material.

The St. Lucie Unit 1 removal times are based on the accumulated fluence values in ASTM E185-82. The NRC has accepted the accumulated fluence approach previously for the St. Lucie Unit 1 capsule schedule [Reference B-18].

The St. Lucie Unit 2 program is a four capsule withdrawal schedule program, in accordance with ASTM E185-82.

The capsules that have been removed are reviewed relative to the ASTM E185-82 criteria so that the remaining capsule and schedule can yield the most bounding data for future operation of the reactor vessel. The removal times are based on the accumulated fluence values in ASTM E185-82. The Unit 2 surveillance capsules contain material from intermediate shell plate, which is the controlling material for this plate-limited vessel.

The Units 1 and 2 reactor vessel surveillance capsule removal schedules require revision to provide meaningful data for the 60-year license renewal period. The proposed schedules were revised in accordance with ASTM E185-82 and GALL Report recommendations.

Appendices A1 and A2 include the changes to the surveillance capsule schedules listed in Unit 1 UFSAR Table 5.4-3, and Unit 2 UFSAR Table 5.3-9.

The attributes described below are based on the revised surveillance capsule schedules.

**Scope**

This subprogram manages the aging effect of reduction in fracture toughness on the reactor vessel materials (beltline plates and welds) due to neutron irradiation embrittlement by performing Charpy V-notch and tensile tests on the reactor vessel irradiated specimens.

**Preventive Actions**

This is a monitoring subprogram; as such, preventive actions are not required.

**Parameters Monitored or Inspected**

Monitored parameters include fracture toughness and tensile strength as measured by Charpy V-notch and tensile test results for irradiated specimens of reactor vessel plate and weld materials. Additionally, accumulated neutron fluence is monitored utilizing surveillance capsule dosimetry.

**Detection of Aging Effects**

Fracture toughness values that are lower than predicted provide indications of unexpected accelerated aging of the reactor vessel materials. Fracture toughness values are determined using calculations of vessel fluence and empirical results from Charpy V-notch testing of irradiated specimens.

**Monitoring and Trending**

Empirical material fracture toughness and accumulated neutron fluence data are obtained from the vessel irradiated specimen surveillance. This data and the trend curves from NRC

Regulatory Guide 1.99 provide the basis for the value for reference temperature for nil-ductility transition ($RT_{NDT}$) and for determining reactor vessel heatup and cooldown limits. These data are monitored and trended to ensure continuing reactor vessel integrity. Both Units contain a sufficient number of capsules to monitor fluences for the extended period of operation. The surveillance capsule withdrawal schedules are specified in Chapter 5 of the Unit 1 UFSAR Supplement provided in Appendix A1, and Chapter 5 of the Unit 2 UFSAR Supplement provided in Appendix A2, and have been revised for the extended period of operation as necessary. Future decisions concerning the frequency of withdrawal of surveillance capsules will be based on changes in fuel type or fuel loading pattern.

**Acceptance Criteria**

Values of $RT_{NDT}$ are calculated based on test results and compared with Regulatory Guide 1.99 trend curves. Surveillance data that fall outside of the defined "credible range" may require further evaluation. The reference temperature for pressurized thermal shock ($RT_{PTS}$) values must also be within the screening criteria of 10 CFR 50.61.

**Confirmation Process**

Periodic testing of the vessel irradiated specimens provides advance indication of future material deterioration. Present testing can be used to validate the accuracy of previous predictions.

**Operating Experience and Demonstration**

The Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram is NRC approved, meets the requirements of 10 CFR 50, Appendix H, and has been in effect since the initial plant start-up. This subprogram has been updated over the years and has provided experience in addressing reduction in fracture toughness. St. Lucie Units 1 and 2 pressure-temperature limit curves have been updated using results from the vessel surveillance capsule specimen evaluations. St. Lucie Units 1 and 2 have been evaluated to have values for $RT_{PTS}$ that are within the acceptance criteria of 10 CFR 50.61.

### 3.2.12.2 REACTOR VESSEL INTEGRITY PROGRAM - FLUENCE AND UNCERTAINTY CALCULATIONS SUBPROGRAM

**Scope**

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline plates and welds.

**Preventive Actions**

This is a monitoring program; as such, preventive actions are not required.

**Parameters Monitored or Inspected**

The monitored parameters are the reactor vessel accumulated neutron fluence values, which are currently predicted based on analytical models meeting the requirements of Draft NRC Regulatory Guide DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," and are benchmarked using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram.

**Detection of Aging Effects**

Accumulated fluence values in excess of predicted values can result in lower fracture toughness values in reactor vessel materials due to irradiation embrittlement. The potential for these effects is determined using neutron calculations of vessel fluence, empirical results from Charpy V-notch tests of irradiated specimens, and capsule dosimetry, in accordance with the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram.

**Monitoring and Trending**

Neutron fluence and uncertainty calculations are performed to predict the accumulated fast neutron fluence. These calculations are verified using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained.

**Acceptance Criteria**

The results of the fluence uncertainty calculations are to be within the NRC suggested limit of ±20%. Calculated fluence values for fast neutrons (above 1.0 MeV) are compared with measured values. This methodology represents a continuous validation process to ensure that no biases have been introduced and that the uncertainties remain comparable to the reference benchmarks.

**Confirmation Process**

The analytical predictions of reactor vessel fast neutron fluence are validated using dosimeter data from the irradiated specimens. Cavity (ex-vessel) dosimetry may also be used to supplement surveillance capsule data.

**Operating Experience and Demonstration**

The neutron fluence and uncertainty calculations for St. Lucie Units 1 and 2 have been performed in accordance with the guidelines of Draft Regulatory Guide DG-1053 and validated using data obtained from the capsule dosimetry. The results of the fluence uncertainty values are to be within the NRC-suggested limit of ±20%. This has been validated by the comparison of the calculated fluence values with measurement values. This methodology represents a continuous validation process to ensure that no biases have been introduced, and that the uncertainties remain comparable to the reference benchmarks.

FPL Letter L-2001-65 [Reference B-19], Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251, April 19, 2001, provided information in response to request for additional information (RAI) 3.9.13.2-1 concerning the database, the data processing (including computer codes) and the associated calculations that demonstrate adherence to the requirements of Draft Regulatory Guide DG-1053. For St. Lucie Units 1 and 2, the methodology is essentially the same as identified in the RAI response, but the databases are plant-specific.

### 3.2.12.3 REACTOR VESSEL INTEGRITY PROGRAM - MONITORING EFFECTIVE FULL POWER YEARS SUBPROGRAM

**Scope**

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessels to ensure that the pressure-temperature limit curves and end-of-life reference temperatures are not exceeded.

**Preventive Actions**

This is a monitoring program; as such, preventive actions are not required.

**Parameters Monitored or Inspected**

The monitored parameters are the reactor vessels' equivalent time at full power in EFPYs.

**Detection of Aging Effects**

EFPY calculations are utilized for the prediction of total accumulated fast neutron fluence and the determination of the reduction in fracture toughness of reactor vessel critical materials.

**Monitoring and Trending**

This subprogram monitors the accumulated reactor vessel EFPYs to be used in predicting the accumulated fast neutron fluence. Each St. Lucie Unit is monitored to determine the EFPYs of operation. These data are used to validate the applicability of the pressure-temperature limit curves for the next operating cycle.

**Acceptance Criteria**

Calculated EFPYs shall not exceed the St. Lucie Units 1 and 2 Technical Specification limits for the validity of the pressure-temperature limit curves.

**Confirmation Process**

The EFPYs of plant operation are based on core thermal power. EFPY values are derived by accumulating time at the measured thermal power relative to rated thermal power. Data are collected for both St. Lucie reactor vessels. The EFPY calculations are used to verify the continued validity of the pressure-temperature limit curves and PTS values.

**Operating Experience and Demonstration**

The EFPYs calculations are used to verify the continued validity of the pressure-temperature limit curves and PTS values. Plant-specific experience has proven this an effective process to assure continued validity of the pressure-temperature curves and the PTS values.

## 3.2.12.4 REACTOR VESSEL INTEGRITY PROGRAM - PRESSURE-TEMPERATURE LIMIT CURVES SUBPROGRAM

### Scope

This subprogram provides pressure-temperature limit curves for the St. Lucie Units 1 and 2 reactor vessels to establish the Reactor Coolant System normal operating limits.

### Preventive Actions

Pressure-temperature limit curves are provided to prevent or minimize the potential of damaging the reactor vessel materials. The curves are included in the Technical Specifications and applicable operating procedures.

### Parameters Monitored or Inspected

The pressure-temperature limit curves specify maximum allowable pressure as a function of Reactor Coolant System temperature. Reactor Coolant System pressures and temperatures at St. Lucie Units 1 and 2 are maintained within these limits.

### Detection of Aging Effects

The pressure-temperature limit curves are not provided for the detection of aging effects, but rather to prevent or minimize potential for damage to the reactor vessel materials.

### Monitoring and Trending

The pressure-temperature limit curves are valid for a period expressed in EFPYs. These curves shall be updated prior to exceeding the EFPYs for which they are valid. The time period for updating pressure-temperature limit curves may change if conditions such as changes in fuel type or fuel loading pattern occur.

### Acceptance Criteria

NRC approved pressure-temperature limit curves must be in place for continued plant operation.

### Confirmation Process

The pressure-temperature limit curves are verified in accordance with the FPL Quality Assurance Program. These pressure-temperature limit curves are NRC approved prior to use, and validated using data obtained from the surveillance capsule specimens.

### Operating Experience and Demonstration

FPL utilizes pressure-temperature limit curves for St. Lucie Units 1 and 2 that have been updated using the results of data obtained from the surveillance capsules. The pressure-temperature limit curves have been developed utilizing an industry methodology that has been approved by the NRC. The pressure-temperature limit curves provide sufficient operating margin while preventing or minimizing the potential for damage to the reactor vessel materials.

Based on the above, the implementation of the enhanced Reactor Vessel Integrity Program provides an effective program for managing the aging effect of reduction in fracture toughness on the reactor vessels such that the components within the scope of license renewal will perform their intended functions in accordance with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.13 STEAM GENERATOR INTEGRITY PROGRAM

As specified in Chapter 3, the Steam Generator Integrity Program is credited for aging management of the steam generators in the Reactor Coolant Systems.

The Steam Generator Integrity Program is consistent with the ten attributes of Aging Management Program XI.M19, "Steam Generator Tube Integrity," specified in the GALL Report [Reference B-2]. In addition, the St. Lucie program scope includes the Unit 2 steam generator tube support lattice bars, and credits sludge lancing as a preventive action for secondary-side steam generator tube degradation, and bundle flushing to minimize flow accelerated corrosion of the Unit 2 carbon steel tube support lattice bars.

**Operating Experience and Demonstration**

The Steam Generator Integrity Program has been effective in ensuring timely detection and correction of the aging effects of cracking and loss of material in steam generator tubes. Tube plug cracking appears to have been related to susceptible heats of material and improper heat treatment, or improper installation.

The Steam Generator Integrity Program is consistent with the guidance provided in NEI 97-06, "Steam Generator Program Guidelines" [Reference B-20], which has undergone extensive industry and NRC review. The current steam generator inspection activities have been evaluated against industry recommendations provided by EPRI and the steam generator suppliers. The overall effectiveness of the program is supported by the excellent steam generator operating experience and favorable inspection results.

Results of previous steam generator inspections and the assessment of potential steam generator aging mechanisms have been evaluated for St. Lucie Units 1 and 2. The evaluations provide a discussion of the design features present in the St. Lucie steam generators that minimize the potential for rapid steam generator degradation. These design features, in addition to the currently specified inspections, ensure that the steam generator intended functions will be maintained in the period of extended operation.

Based on the above, the continued implementation of the Steam Generator Integrity Program provides reasonable assurance that the aging effects will be managed such that the steam generator components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

## 3.2.14 SYSTEMS AND STRUCTURES MONITORING PROGRAM

As identified in Chapter 3, the Systems and Structures Monitoring Program is credited for aging management of specific component/commodity groups in the following systems and structures:

Systems

| | |
|---|---|
| Auxiliary Feedwater and Condensate | Intake Cooling Water |
| Chemical and Volume Control | Main Feedwater and Steam Generator Blowdown |
| Component Cooling Water | Main Steam, Auxiliary Steam, and Turbine |
| Containment Cooling | Miscellaneous Bulk Gas Supply |
| Containment Isolation | Primary Makeup Water |
| Containment Spray | Safety Injection |
| Diesel Generator and Support Systems | Turbine Cooling Water (Unit 1) |
| Fire Protection | Ventilation |
| Fuel Pool Cooling | Waste Management |
| Instrument Air | |

Structures

| | |
|---|---|
| Component Cooling Water Areas | Intake Structures |
| Condensate Storage Tank Enclosures | Reactor Auxiliary Buildings |
| Containments | Steam Trestle Areas |
| Diesel Oil Equipment Enclosures | Turbine Buildings |
| Emergency Diesel Generator Buildings | Ultimate Heat Sink Dam |
| Fuel Handling Buildings | Yard Structures |
| Intake, Discharge, and Emergency Cooling Canals | |

This program is plant-specific. The GALL Report [Reference B-2] includes an Aging Management Program XI.S6, "Structures Monitoring Program." The structural aspects of the Systems and Structures Monitoring Program are consistent with the GALL program. However, the St. Lucie program includes the systems and structures listed above.

The program will be enhanced to provide guidance for the following: managing the aging effects of inaccessible concrete, performing inspections of insulated equipment and piping, and evaluating masonry wall degradation and uniform corrosion. Commitment dates associated with the enhancements to this program are contained in Appendix A.

### Scope

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling (mechanical components only), loss of seal, and change in material properties for the systems and structures listed above. The program provides for visual inspection and examination of accessible surfaces of systems, structures, and components, including welds and bolting. Inspection of insulated piping and equipment is performed by removal of the insulation to gain visual access to the surfaces being inspected. As an alternative, computed radiography may be used to determine if significant external corrosion is present on insulated equipment. The program also includes leak inspection of selected Intake Cooling Water System and Chemical and Volume Control System valves, piping, and fittings.

### Preventive Actions

External surfaces of carbon steel valves, piping, and fittings; cast iron equipment; and surfaces of steel structures and supports are coated to minimize corrosion. However, coatings are not credited in the determination of aging effects requiring management.

### Parameters Monitored or Inspected

Surface conditions of structures, system components, piping, and supports are monitored through visual examinations to determine the existence of external corrosion and in some cases, internal corrosion. The monitoring of concrete and components is consistent with the guidelines provided in ACI 349.3R-96, "Evaluation of Existing Nuclear Safety Related Concrete Structures" and SEI/ASCE 11-99, "Guideline for Structural Condition Assessment of Existing Buildings." The parameters monitored are selected based on industry and plant experience to ensure that aging degradation that could lead to loss of intended function will be identified and addressed. Concrete and masonry parameters monitored include exposed rebar, cracking, rust bleeding, spalling, scaling, other surface irregularities, and settlement. Steel structure parameters monitored include corrosion, flaking, pitting, gouges, cracking, and other surface irregularities. System commodity and component surface conditions are inspected for corrosion (e.g., general corrosion and pitting), cracking, fouling (mechanical components only), other surface irregularities, and leakage for selected systems.

Flexible connectors are monitored for cracking due to embrittlement, and air-cooled heat exchangers are monitored for fouling. Leakage inspections of valves, piping, and fittings at selected locations of the Intake Cooling Water Systems are utilized to detect the presence of internal corrosion. Inspection of weatherproofing materials for deterioration is performed. Aging management of structural components that are inaccessible for inspection is accomplished by inspecting accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components.

### Detection of Aging Effects

The aging effects of loss of material, cracking, fouling (mechanical components only), loss of seal, and change in material properties are detected by visual inspection of surfaces for evidence of degradation or leakage.

**Monitoring and Trending**

Detailed structural and system or component material condition inspections are performed in accordance with approved plant procedures. The results of the visual inspections for systems, structures, and components are documented. The frequency of inspections may be adjusted, as necessary, based on inspection results and industry experience. For insulated piping, a small sample of the sections of systems that operate at less than 212°F will be selected for inspection on the basis of piping geometry, and potential exposure to rain or other conditions that could result in wetting of the insulation.

The inspection schedule varies depending on the system, structure, or component being inspected. These frequencies are based on St. Lucie plant experience considering 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.

Personnel responsible for the performance of inspections and evaluation of inspection results are qualified in accordance with the Engineering Training Program.

**Acceptance Criteria**

Detailed structural and system or component material condition inspections are performed in accordance with approved plant procedures. Existing procedures include detailed guidance for inspecting and evaluating the material condition of systems, structures, and components within the scope of this program. The guidance includes specific parameters to be monitored and criteria to be used for evaluating identified degradation. In addition, the procedures provide sample forms to be used to document the analysis and the assessment, and a system checklist for documenting relevant information from a system walkdown.

**Confirmation Process**

Any required follow-up inspection will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

**Operating Experience and Demonstration**

The Systems and Structures Monitoring Program has been an ongoing program at St. Lucie Nuclear Plant and has been enhanced over the years to include the best practices recommended by industry guidance. Additionally, the Systems and Structures Monitoring Program supports implementation of the NRC Maintenance Rule (10 CFR 50.65).

Systems, structures, and components have been periodically inspected for material condition at St. Lucie Units 1 and 2. As part of implementation of the Maintenance Rule, baseline inspections were performed. Periodic inspections continue to be performed as part of this program. Degraded conditions are documented in accordance with the corrective action program. As part of the corrective action program, actions to prevent recurrence are identified, such as plant modifications or program enhancements to address the affected item as well as related generic implications. Periodic evaluations are performed to assess and initiate enhancements to plant programs.

Based on the above, the continued implementation of the Systems and Structures Monitoring Program provides reasonable assurance that the aging effects will be managed such that the systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the St. Lucie Units 1 and 2 CLBs for the period of extended operation.

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# APPENDIX C

## PROCESS FOR IDENTIFYING AGING EFFECTS REQUIRING MANAGEMENT FOR NON-CLASS 1 COMPONENTS

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# 1.0 INTRODUCTION

FPL utilized industry guidance, developed by the Babcock and Wilcox (B&W) Owners Group, for determining aging effects requiring management for the non-Class 1 components and steel in fluids associated with structural components. The guidance was reviewed for applicability, and tailored to address St. Lucie Units 1 and 2 materials and environments and to incorporate specific aging mechanisms/effects based upon plant experience (i.e., lessons learned). This appendix summarizes the process for identification of aging effects requiring management for non-Class 1 components.

The potential aging effects evaluated include the following:

- loss of material
- cracking
- fouling
- loss of mechanical closure integrity
- reduction in fracture toughness
- distortion/plastic deformation

Internal operating environments evaluated are:

- treated water - primary
- treated water - secondary
- treated water - borated
- treated water - other
- raw water - salt water
- raw water - city water
- raw water - drains
- air/gas
- fuel oil
- lubricating oil

External operating environments evaluated are:

- outdoor
- indoor - not air conditioned
- indoor - air conditioned
- containment air
- borated water leaks
- buried (above groundwater elevation)

- embedded/encased (in concrete)

A component is considered susceptible to a wetted environment when the component is submerged, has the potential to pool water, or is subject to external condensation.

For components that are submerged, an applicable internal environment listed above may be specified.

Where wetted conditions exist (e.g., due to condensation), the environment is annotated accordingly.

Note: Other than borated water leaks, fluid leakage is not considered in the aging management review process. Fluid leakage is considered an event-driven condition and not a normal operating condition. As noted in Christopher I. Grimes (NRC) letter to Douglas J. Walters (NEI), June 5, 1998, aging effects from abnormal events need not be postulated for license renewal [Reference C-1].

# 2.0 COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

In accordance with 10 CFR 54 and NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," [Reference C-2] Appendix B, only passive components are in the scope of review. Within the systems that are in the scope of license renewal, the following are typical components subject to aging management review:

| | | |
|---|---|---|
| ductwork | heat exchangers | pump casings |
| expansion joints | mechanical closure bolting | steam traps |
| flexible hoses | orifices and flow elements | tanks/vessels |
| filters, strainers | piping, tubing, and fittings | valve bodies and bonnets |
| fuel handling equipment | fuel storage racks | |

Many of the components within the scope of license renewal contain gaskets, packing, and seals. However, these items, defined as consumables, are not subject to aging management review since they do not support the component intended functions as established by design codes and are not long-lived.

# 3.0 MATERIALS USED IN NON-CLASS 1 COMPONENTS

The following materials are present in non-Class 1 components within the scope of license renewal:

| | | |
|---|---|---|
| aluminum | titanium | rubber |
| aluminum alloy | copper | Neoprene |
| stainless steel (wrought and cast)<br>nickel alloy | copper alloys (brass, copper nickel, bronze, aluminum brass, aluminum bronze) | vinyl ester<br>glass<br>plastic |
| carbon steel (plain and galvanized) | Monel | Plexiglas<br>rubber coated cloth |
| cast iron | low alloy steel | fiberglass |

Note that some components contain internal and external coatings or linings. For example, Intake Cooling Water piping is cement lined and some valves are rubber lined. These features perform a preventive function, but are not credited for the elimination of aging effects requiring management.

# 4.0 ENVIRONMENTS

## 4.1 INTERNAL ENVIRONMENTS

### 4.1.1 TREATED WATER

Treated water is demineralized water and is the base water for all clean systems. Depending on the system, treated water may involve additional processing. Treated water can be deaerated, and can include corrosion inhibitors, biocides, boric acid, or a combination of these treatments. Within this application, treated water has been subdivided into the following groups based on the chemistry of the water.

- Treated water - primary - Normal operating Reactor Coolant System chemistry
- Treated water - secondary - Normal operating secondary chemistry, including Main Steam, Turbine, Feedwater, Auxiliary Feedwater, Condensate, and Blowdown Systems
- Treated water - borated - Systems that contain borated water except those included in treated water - primary, including Chemical and Volume Control, Spent Fuel Cooling, Emergency Core Cooling, and Sampling Systems
- Treated water - other - All other treated water systems, including Component Cooling Water, Turbine Cooling Water, Emergency Diesel Generator Cooling, Primary Makeup Water, and Unit 2 Demineralized Makeup Water Systems. With the exception of makeup water, all systems utilize corrosion inhibitors and, in some cases, biocides.

Aging effects for materials typically found in treated water environments are summarized in Sections 3.2 though 3.5 of this application.

### 4.1.2 RAW WATER

For St. Lucie Units 1 and 2, raw water constitutes the salt water that comes from the ocean through the intake canal and is used for the main condensers and Intake Cooling Water System, the salt water from Big Mud Creek that is used for the Ultimate Heat Sink, and the city water that is used for the Fire Protection and Service Water Systems. In general, the water has been rough filtered to remove large particles and may contain a biocide additive for control of micro-organisms and macro-organisms. Although city water is purified, it is conservatively classified as raw water for the purposes of aging management review. Within this Application, raw water has been subdivided into the following groups based on the chemistry of the water.

- Raw water - salt water - Salt water used for the main condensers and as the ultimate heat sink
- Raw water - city water - Potable water supplied to the water treatment plant, and the Service Water and the Fire Protection Systems

- Raw water - drains - Fluids collected in building drains. The fluids can be treated water (primary, secondary, borated, or other), raw water (cooling canals or city water), fuel oil, or lubricating oil

Aging effects for materials typically found in raw water environments are summarized in Sections 3.2, 3.3, and 3.5 of this application.

### 4.1.3 AIR/GAS

This environment includes atmospheric air, dry/filtered instrument air, nitrogen, carbon dioxide, hydrogen, and Halon.

Air is composed of mostly nitrogen and oxygen with smaller fractions of various other constituents. The internal surfaces of a majority of components are, at some time, exposed to air. Where air is the intended internal environment, it is supplied in either its natural state or in a dry condition.

Nitrogen is an inert gas used in many nuclear power plant applications to place components in a dry lay-up condition or to provide a cover gas to prevent exposure to oxygen.

Carbon dioxide is a colorless, odorless incombustible gas. Without the presence of moisture, the gaseous carbon dioxide is not a significant contributor to corrosion or other aging effects.

Hydrogen is a colorless, odorless combustible gas.

Halon is a halogenated extinguishing agent used in the Fire Protection System for its ability to chemically react with fire and smother flames. Halon is a non-corrosive gas.

Aging effects for materials typically found in air/gas environments are summarized in Sections 3.2 through 3.4 of this application. Where wetted conditions are determined to exist (e.g., due to condensation), the environment description is amended accordingly, and potential aging effects are addressed.

### 4.1.4 FUEL OIL

This includes fuel oil for the emergency diesel generators. Fuel oil within the scope of license renewal is No. 2 diesel oil. Diesel fuel oil is delivered to St. Lucie Nuclear Plant in tanker trucks and is stored in large tanks to provide an onsite supply of diesel fuel for a specified period of emergency diesel generator operating time. The fuel oil is supplied to the emergency diesel engines through pumps, valves, and piping. Strainers, filters, and other equipment assure that the diesel fuel supplied to the engines is clean and free of contaminants. Aging effects for materials typically found in fuel oil environments are summarized in Section 3.3 of this application.

### 4.1.5 LUBRICATING OIL

This environment is the lubricating oil for emergency diesel generators, pumps, and other components. Also included in this environment are hydraulic oils used in valve actuators. Lubricating oils within the scope of license renewal are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication. Aging effects for materials typically found in lubricating oil environments are summarized in Sections 3.3 and 3.4 of this application.

## 4.2 EXTERNAL ENVIRONMENTS

### 4.2.1 OUTDOOR

The outdoor environment is characterized by moist, salt-laden atmospheric air, temperature 27°F-93°F, 73% average humidity, and exposure to weather, including precipitation and wind. Aging effects for materials typically found in outdoor environments are summarized in Sections 3.2 through 3.6 of this application.

### 4.2.2 INDOOR - NOT AIR CONDITIONED

This includes atmospheric air, a temperature of 104°F maximum (110°F maximum in the Unit 2 Electrical Equipment Room), 73% average humidity, and no exposure to weather. Aging effects for materials typically found in indoor - not air conditioned environments are summarized in Sections 3.2 through 3.6 of this application.

### 4.2.3 INDOOR - AIR CONDITIONED

This includes atmospheric air with a specific temperature/humidity range dependent upon the building/room, and involves no exposure to weather. Typically, the temperature is 70°F-80°F, and the humidity is 45%-55%. Aging effects for materials typically found in indoor – air conditioned environments are summarized in Section 3.5 of this application.

### 4.2.4 CONTAINMENT AIR

This includes atmospheric air, a temperature of 120°F maximum, 73% average humidity, radiation total integrated dose rate of 2 rads per hour (excluding equipment located inside the reactor cavity), and no exposure to weather. Aging effects for materials typically found in containment air environments are summarized in Sections 3.2 through 3.5 of this application.

### 4.2.5 BORATED WATER LEAKS

This environment includes exposure to leakage from borated water systems. The concentrations of boric acid in the Reactor Coolant System and other borated water systems are lower than the concentration necessary to cause corrosion. However, borated water that leaks out of systems loses substantial volume due to evaporation, resulting in highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions may be very corrosive for carbon steel.

Aging effects for materials exposed to borated water leak environments are summarized in Sections 3.2 through 3.6 of this application.

### 4.2.6 BURIED

Above groundwater elevation, this environment involves exposure to soil/fill. Below groundwater elevation, this environment involves exposure to soil/fill and groundwater. Groundwater contains aggressive chemicals that can attack susceptible materials. Although all buried piping and mechanical components are above groundwater elevation, buried components are assumed to be susceptible to corrosion. The only exception to this is buried piping located under a concrete slab. In this case, it is unlikely that the surface of the pipe will be exposed to a wetted environment and, therefore, it is not considered susceptible to external corrosion. Aging effects for materials typically found in buried environments are summarized in Sections 3.3 through 3.6 of this application.

### 4.2.7 EMBEDDED/ENCASED

This environment is associated with reinforcing or embedded steel or piping in concrete. Aging effects for materials typically found in embedded/encased environments are summarized in Sections 3.3 through 3.5 of this application.

# 5.0 POTENTIAL AGING EFFECTS

Potential aging effects were determined based on materials and environments. Aging effects are considered to require management if the effects could cause loss of component intended function during the period of extended operation. The potential aging effects and associated mechanisms evaluated for non-Class 1 components are as discussed below.

## 5.1 LOSS OF MATERIAL

Loss of material may be due to general corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion/corrosion, erosion, microbiologically influenced corrosion, selective leaching, wear, and aggressive chemical attack.

General corrosion is the result of a chemical or electrochemical reaction between the material and the environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution, and sometimes corrosion product buildup. General corrosion on components exposed to air tends to form a protective oxide film on the components that prevents further significant corrosion. This is typically true for components not exposed to other sources of moisture such as rain, condensation, or frequent leakage. Wrought austenitic stainless steel, copper, copper alloys, CASS, and nickel-based alloys are not susceptible to general corrosion except when subjected to aggressive environments. Carbon and low alloy steels are susceptible to external general corrosion in all areas with the exception of those exposed to a controlled, air conditioned environment, and those applications where the metal temperature is greater than 212°F. Additionally, galvanized carbon steel is not considered susceptible to general corrosion except where buried, submerged in fluid, or subject to wetting other than humidity, such as salt spray.

Pitting corrosion is a form of localized attack that results in depressions in the metal. For treated water systems, oxygen is required for initiation of pitting corrosion with contaminants, such as halogens or sulfates, required for continued metal dissolution. Pitting corrosion occurs when passive films in local areas attack passive materials. Once a pit penetrates the passive film, galvanic conditions occur because the metal in this pit is anodic relative to the passive film. Maintaining adequate flow rate over this exposed surface of a component can inhibit pitting corrosion. However, stagnant or low flow conditions are assumed to exist in all systems where dead legs of piping, such as vents or drains, exist. Pitting corrosion is more common with passive materials, such as austenitic stainless steels, than with non-passive materials. Most materials of interest are susceptible to pitting corrosion under certain conditions. For treated water environments, stainless and carbon steels are assumed susceptible to pitting in the presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb when dissolved oxygen is in excess of 100 ppb. However, like general corrosion, moisture must be present, and those metals exposed to a controlled, air conditioned environment or an operating temperature greater than 212°F are not susceptible to external pitting corrosion. Because pitting of stainless steel material in an outdoor environment at St. Lucie Nuclear Plant is dependent on its location within the plant site, these materials were evaluated based upon experience and visual inspections. Typically, stainless steel materials located near the plant discharge canal are more susceptible due to the salt spray environment. Additionally, bronze and brass are considered susceptible to pitting when the zinc content is greater than 15%, and aluminum bronze is considered susceptible to pitting when the aluminum content is greater than 8%.

Loss of material due to galvanic corrosion can occur only when materials with different electrochemical potentials are in contact within an aqueous environment. Generally, the effects of galvanic corrosion are precluded by design (e.g., isolation to prevent electrolytic connection or using similar materials). In galvanic couples involving brass, carbon steel, cast iron, copper, and stainless steel materials, the lower potential (more anodic) carbon steel, cast iron, and low-alloy steel would be preferentially attacked.

Crevice corrosion occurs in a wetted or buried environment when a crevice or area of stagnant or low flow exists that allows a corrosive environment to develop in a component. It occurs most frequently in joints and connections, or points of contact between metals and non-metals, such as gasket surfaces, lap joints, and under bolt heads. Crevice corrosion is strongly dependent on the presence of dissolved oxygen. For environments with extremely low oxygen content (less than 0.1 ppm), crevice corrosion is considered insignificant. Carbon steel, cast iron, low alloy steels, stainless steel, copper, and nickel base alloys are all susceptible to crevice corrosion. However, experience at St. Lucie Units 1 and 2 shows that crevice corrosion is not a significant aging mechanism for components subjected to treated water.

Erosion is a mechanical action of fluid and/or particulate matter on a metal surface, without the influence of corrosion. Equipment exposed to moving fluids is vulnerable to erosion. These include piping, valves, vanes, impellers, etc. General erosion occurs under high velocity conditions, turbulence, and impingement. Geometric factors are extremely important. Typical forms of erosion include liquid impingement, flashing, and cavitation. Systems and components are typically designed to preclude these mechanisms. Additionally, these mechanisms are quite severe and would be discovered early in a component's life. In general, erosion mechanisms are not considered aging effects requiring management during the period of extended operation. An exception is the Unit 1 and 2 auxiliary feedwater pump recirculation lines downstream of the restriction orifices, and the Unit 2 component cooling water piping downstream from the control room air conditioners. Loss of material due to erosion has been experienced in these lines and FPL has elected to manage this effect by inspection in lieu of design modifications at St. Lucie Units 1 and 2.

Erosion/corrosion occurs when fluid or particulate is also corrosive. Erosion/corrosion is influenced by 1) fluid flow velocity, 2) geometry, 3) environmental characteristics (temperature and fluid chemistry), and 4) material susceptibility. Carbon and low alloy steels are most susceptible to erosion/corrosion. Higher alloy steels, nickel based alloys, and stainless steels are considered resistant to both erosion and erosion/corrosion. Most of the treated water systems are immune from erosion/corrosion because of their non-corrosive service fluids. One exception to the above involves high-energy piping systems that are susceptible to a form of erosion/corrosion called flow accelerated corrosion (FAC). FAC involves the dissolution of protective oxides on carbon and low alloy steel components, and continual removal of these dissolved oxides by flowing fluid. The Main Steam, Auxiliary Steam, Main Feedwater, and Steam Generator Blowdown Systems have been identified as being susceptible to FAC.

Microbiologically influenced corrosion (MIC) is a form of localized, corrosive attack accelerated by the influence of microbiological activity due to the presence of certain organisms in a wetted or buried environment. Microbiological organisms can produce corrosive substances, as a byproduct of their biological processes, that disrupt the protective oxide layer on the component materials and lead to a material depression similar to pitting corrosion. Microscopic organisms have been observed in mediums over a wide range of temperatures and pH values. However, for the purpose of aging management review, loss of material due to MIC is not considered significant at temperatures greater than 210°F or pH greater than 10.

Selective leaching (also known as dealloying) is the dissolution of one element from a solid alloy by corrosion processes in a wetted or buried environment. The most common forms of selective leaching are graphitic corrosion with the loss of the iron matrix in gray cast iron under harsh conditions, and dezincification with the removal of zinc from susceptible brass or bronze components. The addition of small amounts of alloying elements such as tin, phosphorus, arsenic, and antimony is effective in inhibiting this attack in copper-zinc alloys. Therefore, selective leaching of brass and other alloys applies only to "uninhibited" materials.

Mechanical wear is defined as damage to a solid surface by removal of parts of its material via mechanical action of a contacting solid, liquid, or gas. There are three primary types of wear: abrasive, adhesive, and erosive. Abrasive wear (scouring and gouging) is the removal of material from a surface when hard particles slide or roll across the surface under pressure. Scouring and gouging are often due to loose particles entrapped between the surfaces that are in relative motion. Adhesive wear (galling, scoring, seizing, fretting, and scuffing) involves the transference of material from one surface to another during relative motion or sliding due to a process called solid-state welding (i.e., particles that are removed from one surface are either temporarily or permanently attached to the other surfaces). Erosive wear is the mechanical wear action of a fluid and/or particulate matter on a solid surface. Erosive wear is also known as erosion, and has been discussed above.

Aggressive chemical attack is corrosion that may be localized or general, and is caused by a corrodent that is particularly active on a specified material. Boric acid is used in PWRs as a reactivity agent. The concentrations of boric acid in the Reactor Coolant Systems and other borated water systems are lower than the concentration necessary to cause corrosion. However, borated water that leaks out of systems loses substantial volume due to evaporation, resulting in highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions may be very corrosive for carbon steel. Most carbon steel components located inside the radiation control area were considered susceptible to boric acid corrosion. Other metals, such as copper, copper alloys, nickel, nickel alloys, and aluminum, are resistant to boric acid corrosion. [Reference C-3]

## 5.2 CRACKING

Cracking is non-ductile failure of a component due to stress corrosion, fatigue, or embrittlement. Cracking resulting from fatigue is typically precluded by design. However, an exception identified is the charging pump fluid blocks, which are susceptible to high cycle fatigue. The analysis of the potential for cracking due to metal fatigue is a TLAA and is addressed in Section 4.3 of this application.

SCC requires a combination of a susceptible material, a corrosive environment, and tensile stress. SCC can be categorized as either transgranular stress corrosion cracking (TGSCC) or intergranular stress corrosion cracking (IGSCC), depending on the cracking morphology. For austenitic stainless steels, TGSCC is the normal cracking mode unless the material is in a sensitized condition. As such, SCC of such materials is assumed transgranular in nature unless specified as IGSCC.

The tensile stresses necessary to induce SCC may be either applied (external) or residual (internal), but must be at or near the material's yield point. The corrosive environments that induce SCC are highly material dependent. For austenitic stainless steels and nickel-based alloys in treated water, the relevant conditions required for SCC are the presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb, and elevated temperature. For St. Lucie treated and raw water environments, a temperature criterion of greater than 140°F is utilized for susceptibility of austenitic stainless steels and nickel based alloys to SCC. However, SCC has been observed elsewhere in high purity water (i.e., halogens and sulfates less than 150 ppb and 100 ppb, respectively) at temperatures greater than 200°F with dissolved oxygen levels greater than 100 ppb. IGSCC of stainless steels is generally associated with sensitized material. Sensitization of unstabilized austenitic stainless steel is characterized by a depletion of chromium at the grain boundaries with accompanying precipitation of a network of chromium carbides occurring at elevated temperatures. Generally, an exposure period of one hour to temperatures between 800°F and 1500°F are required to fully develop the network of intergranular carbides. However, studies have shown that the thermal effects of welding followed by prolonged exposure to elevated temperatures below the normal sensitization range can also fully develop the intergranular carbide network, thereby rendering the alloys susceptible to intergranular attack (IGA) and IGSCC. Sensitization to IGSCC can occur as low as 480°F over a long period of service. Because the depletion of chromium at or near grain boundaries is caused by the formation of carbides, the carbon content of the austenitic stainless steel is critical as to the susceptibility of the material to sensitization.

For stainless steels exposed to atmospheric conditions, IGSCC is considered when the steel is exposed to high levels of contaminants (e.g., salt water) and only if the material is in a sensitized condition. Experience at St. Lucie has also revealed susceptibility to TGSCC in the non-stress relieved heat affected zone regions of weld joints of stainless steel piping located in trenches exposed to marine atmospheric conditions. The proximity of these trenches to the discharge canals on the ocean side of the plant promotes the concentration of chlorides from the salt air environment. Additionally, St. Lucie Units 1 and 2 have experienced SCC on previously heat traced piping in the Chemical and Volume Control

Systems due to external contamination. This piping is no longer heat traced, however, FPL continues to be inspected for SCC.

Apart from these exceptions, most austenitic stainless steel and nickel base alloys are resistant to SCC at temperatures less than 140°F.

NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants," NRC Information Notice 79-19, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants," and NRC IE Circular 76-06, "Stress Corrosion Cracks in Stagnant, Low Pressure Stainless Steel Piping Containing Boric Acid Solution at PWRs," describe several instances of through-wall cracking in stainless steel piping in stagnant borated water systems. NRC Bulletin 79-17 required licensees to review safety-related systems that contain stagnant, oxygenated, borated water. For these identified systems, licensees were requested to review pre-service non-destructive examinations (NDE) results, inservice NDE results, and chemistry controls. Also, ultrasonic and visual examinations of representative samples of circumferential welds were performed. The results of these reviews and inspections at St. Lucie Units 1 and 2 identified no anomalies in chemistry or indications of SCC at welds. All of the instances of SCC in the nuclear power industry have identified the presence of halogens, such as chlorides, in the failed component. These occurrences most likely resulted from the inadvertent introduction of contaminants into the system. As discussed above, SCC can occur in stainless steel at ambient temperature if exposed to a harsh enough environment (i.e., with significant contamination). However, these conditions are considered to be event-driven, resulting from the breakdown of quality controls for water chemistry and, thus, not representative of the normal environment associated with treated water.

For carbon steels, SCC occurs most commonly in the presence of aqueous chlorides. Industry data does not indicate a significant problem of SCC for low-strength carbon steels. For these reasons, SCC of carbon steels is not an aging effect requiring management.

Material fatigue resulting from vibration has been observed in the nuclear power industry and can result in crack initiation/growth. Vibration-induced fatigue is fast acting and typically detected early in a component's life, and corrective actions are initiated to prevent recurrence. Corrective actions typically involve modifications to the plant, such as addition of supplemental restraints to a piping system, replacement of tubing with flexible hose, etc. Based upon these considerations, cracking due to vibration-induced fatigue is not considered an aging effect for the period of extended operation.

Embrittlement is an aging mechanism that can cause cracking of rubber, neoprene, fiberglass, vinyl ester, plexiglas, plastic, or coated canvas materials at St. Lucie Units 1 and 2. Embrittlement can occur due to age, temperature, or irradiation.

## 5.3 FOULING

Fouling may be due to accumulation of particulates or macro-organisms (biological).. Fouling is an aging effect for mechanical components that can cause loss of heat transfer intended function at St. Lucie Units 1 and 2. Additionally, macrofouling of heat exchanger tubes has resulted in the loss of material due to high localized velocities (erosion-corrosion). Biological fouling can also lead to environmental conditions conducive to MIC and crevice corrosion. Fouling evaluated for St. Lucie includes macrofouling (macro-organisms, grass, etc.), and particulate fouling due to precipitation or corrosion products. Fouling is not considered an aging effect for components with an intended function of filtration (e.g., a strainer). In these cases, the component is designed to foul, and this short-term effect is addressed by normal system operating practices.

## 5.4 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity is an aging effect associated with bolted mechanical closures that results in failure of the mechanical joint. The following potential mechanisms were evaluated for their effects on mechanical closure integrity: 1) loss of pre-load resulting from cyclic loading, gasket creep, thermal or other effects, 2) cracking of bolting material, and 3) loss of bolting material due to corrosion.

Loss of pre-load of mechanical closures can occur due to settling of mating surfaces, relaxation after cyclic loading, gasket creep, and loss of gasket compression due to differential thermal expansion. The effects of these mechanisms are the same as that of a degraded gasket; that is, the potential for external leakage of the internal fluid at the mechanical joint. Since the ASME Code does not consider gaskets, packing, seals, and O-rings to perform a pressure-retaining function, these components are typically not considered to support an intended function and are not within the scope of license renewal. Thus, the aging mechanisms associated with loss of pre-load, described above, are not considered to require management for non-Class 1 components during the period of extended operation. An exception to this would be a situation where a gasket/seal is utilized to provide a radiological boundary/barrier and thus may support an intended function. Based on the aging management review of the non-Class 1 systems at St. Lucie Units 1 and 2, there were no cases where gasket/seals are relied on to support component intended functions.

High stress in conjunction with an aggressive environment can cause cracking of certain bolting materials due to SCC. As identified in NRC IE Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," and NRC Generic Letter 91-17, "Generic Safety Issue 29, 'Bolting Degradation or Failure in Nuclear Power Plants,'" cracking of bolting in the industry has occurred due to SCC. These instances of SCC have been primarily attributed to the use of high yield strength bolting materials, excessive torquing of fasteners, and contaminants, such as the use of lubricants containing molybdenum disulfide ($MoS_2$). In response to NRC IE Bulletin 82-02, FPL verified that at St. Lucie Units 1 and 2:

- Specific maintenance procedures were in place to address bolted closures.
- The procedures in use addressed detensioning and retensioning practices and gasket installation and controls.

- Threaded fastener lubricants used in pressure boundary applications have specified maximum allowable limits for chloride and sulfur content to minimize susceptibility to SCC environments.
- Maintenance crew training on threaded fasteners is performed.

In order for SCC to occur, three conditions must exist: a susceptible material, high tensile stresses, and a corrosive environment. At St. Lucie, the potential for SCC of fasteners is minimized by utilizing ASTM A193, Gr. B7 bolting material and limiting contaminants, such as chlorides and sulfur, in lubricants and sealant compounds. Additionally, sound maintenance bolt torquing practices are used to control bolting material stresses. The use of ASTM A193, Gr. B7 bolting specifies a minimum yield strength of 105 Ksi, which is well below the 150 Ksi threshold value specified in EPRI NP-5769, "Degradation of Bolting in Nuclear Power Plants," April 1988. Bolting fabricated in accordance with this standard could be expected to have yield strengths less than 150 Ksi. However, since the maximum yield strength is not specified for this bolting material, absolute assurance cannot be provided that the yield strength of the bolting would not exceed 150 Ksi. For these cases, the combination of specifying ASTM A193 Gr. B7 bolting material, control of bolt torquing, and control of contaminants will ensure that SCC will not occur. These actions have been effective in eliminating the potential for SCC of bolting materials. The results of a review of the St. Lucie condition report (1992 through 2000) and metallurgical report (1984 through 2000) databases support this conclusion in that no instances of bolting degradation due to SCC were identified. Additionally, review of NRC generic communications did not identify any recent bolting failures attributed to SCC. Therefore, cracking of bolting material due to SCC is not considered an aging effect requiring management at St. Lucie Units 1 and 2.

Loss of bolting material, on the other hand, can result in failure of the mechanical joint and the loss of a component's pressure boundary integrity. Therefore, the potential for this effect must be addressed. Most carbon steel bolting is in a dry environment and coated with a lubricant, thus general corrosion of bolting has not been a major concern in the industry. Additionally, stainless steel fasteners are immune to loss of material due to general corrosion. Corrosion of fasteners has only been a concern where leakage of a joint occurs, specifically, when bolting is exposed to aggressive chemical attack such as that resulting from borated water leaks.

Aggressive chemical attack is corrosion that may be localized or general, and is caused by a corrodent that is particularly active on a specified material. Boric acid is used in PWRs as a reactivity agent. The concentrations in the Reactor Coolant System and other borated water systems are lower than the concentration necessary to cause corrosion. However, borated water that leaks out of systems loses substantial volume due to evaporation, resulting in highly concentrated boric acid solutions or deposits of boric acid crystals. These concentrated solutions may be very corrosive for carbon steel. Loss of mechanical closure integrity due to boric acid corrosion was considered as a potential aging effect for components in proximity to borated water systems.

## 5.5 REDUCTION IN FRACTURE TOUGHNESS

Thermal embrittlement is a mechanism by which the mechanical property fracture toughness is affected as a result of exposure to elevated temperature. CASS materials are susceptible to thermal embrittlement dependent upon material composition and the time at temperature. CASS materials subjected to temperatures >482°F are considered susceptible. Low alloy steels may be subject to embrittlement from exposure to temperatures in the range of 570°F - 1100°F. The loss of fracture toughness may not be accompanied by significant changes in other material properties.

Neutron embrittlement is the loss of fracture toughness resulting from the bombardment of neutrons. The loss of fracture toughness may be accompanied by detectable increases in material hardness. The overall effects of neutron embrittlement on steel are to increase yield strength, decrease the ultimate tensile ductility, and increase the ductile to brittle transition temperature. Neutron embrittlement is considered a potential aging mechanism requiring management only inside the reactor cavity.

## 5.6 DISTORTION/PLASTIC DEFORMATION

Creep is defined as time-dependent strain, or gradual elastic and plastic deformation, of metal that is under constant stress at a value lower than its normal yield strength. Creep is a concern when the component operating temperature approaches or exceeds the recrystallization temperature for the metal. Austenitic stainless steel with temperatures <800°F, and carbon steel and low alloy steels with temperatures <700°F are not susceptible to creep. All St. Lucie Nuclear Plant systems operate <700°F and, thus, are not susceptible to creep.

Stress relaxation is the time-dependent decrease in stress in a solid under constant constraint at constant temperature. The rate of stress relaxation is temperature dependent. As a rule, stress relaxation is not a significant problem at temperatures less than one-half of the melting point. All St. Lucie Nuclear Plant systems operate below the temperature at which stress relaxation occurs and, thus, are not susceptible to stress relaxation.

# 6.0 REFERENCES

C-1 C. I. Grimes (NRC) letter to D. J. Walters (NEI), "License Renewal Issue No. 98-0013, Degradation Induced Human Activities," June 5, 1998.

C-2 NEI 95-10, Revision 3, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Nuclear Energy Institute, January 2000.

C-3 "Handbook of Corrosion Data", American Society of Metals, 1995.

# APPENDIX D

# TECHNICAL SPECIFICATION CHANGES

# TECHNICAL SPECIFICATION CHANGES

The Code of Federal Regulations, Title 10, at 54.22, requires applicants to include any Technical Specification changes, or additions, necessary to manage the effects of aging during the period of extended operation as part of the renewal application. Based on a review of the information provided in the St. Lucie Units 1 and 2 license renewal application and Technical Specifications, no license amendment requests for St. Lucie Units 1 and 2 Technical Specifications are being submitted with this application.