Appendix A

UPDATED
FINAL SAFETY ANALYSIS REPORT
SUPPLEMENT

INTRODUCTION

This appendix contains the Updated FSAR (UFSAR) Supplement required by 10 CFR 54.21(d) for the Turkey Point Units 3 and 4 License Renewal Application (LRA). The LRA contains the technical information required by 10 CFR 54.21(a) and (c). Chapter 3 and Appendix B of the Turkey Point 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 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. The UFSAR Supplement will be incorporated into the Turkey Point Units 3 and 4 UFSAR following issuance of the renewed operating licenses for Turkey Point. Upon inclusion of the UFSAR Supplement in the Turkey Point UFSAR, changes to the descriptions of the programs and activities for their implementation will be made in accordance with 10 CFR 50.59.

UFSAR CHAPTER 4.0 CHANGES

For the combination of normal plus design earthquake loadings, the stresses in the support structures are kept within the limits of the applicable codes.

For the combination of normal plus no-loss-of-function earthquake loadings, the stresses in the support structures are limited to values necessary to ensure their integrity, and to keep the stresses in the Reactor Coolant System components within the allowable limits as given in Appendix 5A.

4.1.5 CYCLIC LOADS

All components in the Reactor Coolant System are designed to withstand the effects of cyclic loads due to reactor coolant system temperature and pressure changes. These cyclic loads are introduced by normal power changes, reactor trip, and startup and shutdown operation. The number of thermal and loading cycles used for design purposes and their bases are given in Table 4.1-8. During unit startup and shutdown, the rates of temperature and pressure changes are limited as indicated in Section 4.4.1. The cycles are estimated for equipment design purposes ~~(40 year life)~~ and are not intended to be an ~~accurate~~ exact representation of actual transients or actual operating experience. For example the number of cycles for unit heatup and cooldown at 100°F per hour was selected as a conservative estimate based on an evaluation of the expected requirements. The resulting number~~, which averages five heatup and cooldown cycles per year,~~ could be increased significantly; however, it is the intent to represent a conservative realistic number rather than the maximum allowed by the design.

Although loss of flow and loss of load transients are not included in Table 4.1-8 since the tabulation is only intended to represent normal design transients, the effect of these transients have been analytically evaluated and are included in the fatigue analysis for primary system components.

Over the range from 15% full power up to but not exceeding 100% of full power, the Reactor Coolant System and its components are designed to accommodate 10% of full power step changes in unit load and 5% of full power per minute ramp changes without reactor trip. The turbine bypass and steam dump system make it possible to accept a step load decrease of 50% of full power without reactor trip.

4.1.6 SERVICE LIFE

The service life of Reactor Coolant System pressure components depends upon the material irradiation, unit operational thermal cycles, quality manufacturing standards, environmental protection, and adherence to established operating procedures.

The reactor vessel is the only component of the Reactor Coolant System which is exposed to a significant level of neutron irradiation and it is therefore the only component which is subject to any appreciable material irradiation effects. The NDTT shift of the vessel material and welds, due to radiation damage effects, is monitored by a radiation damage surveillance program which conforms with ASTM-E 185 standards.

Reactor vessel design is based on the transition temperature method of evaluating the possibility of brittle fracture of the vessel material, as result of operations such as leak testing and heatup and cooldown.

To establish the service life of the Reactor Coolant System components as required by the ASME (part III), Boiler and Pressure Vessel Code for Class "A" Vessels, the unit operating conditions have been established for the initial 40 year design life. These operating conditions include the cyclic application of pressure loadings and thermal transients. The evaluation for extended plant design life concludes that the 40-year design cycles envelope the 60-year extended design life.

The number of thermal and loading cycles used for design purposes are listed in Table 4.1-8.

TABLE 4.1-8

DESIGN THERMAL AND LOADING CYCLES - ~~40~~ 60 YEARS

	Transient Design Condition	Design Cycles	~~Expected Cycles~~
1.	Station heatup at 100°F per hour	200 ~~(5/yr)~~	~~80~~
2.	Station cooldown at 100°F per hour	200 ~~(5/yr)~~	~~80~~
3.	Station loading at 5% of full power/min	14,500 ~~(1/day)~~	~~2500~~
4.	Station unloading at 5% of full power/min	14,500 ~~(1/day)~~	~~2500~~
5.	Step load increase of 10% of full power (but not to exceed full power)	2000 ~~(1/week)~~	~~500~~
6.	Step load decrease of 10% of full power	2,000 ~~(1/week)~~	~~500~~
7.	Step load decrease of 50% of full power	200 ~~(5/year)~~	~~20~~
8.	Reactor trip	400 ~~(10/year)~~	~~40~~
9.	Hydrostatic test at 3107 psig pressure, 100°F temperature	5 ~~(pre-operational)~~	~~2~~
10.	Hydrostatic test at 2435 psig pressure and 400°F temperature	150 ~~(post-operational)~~	~~30~~

11. Steady state fluctuations - the reactor coolant average temperature for purposes of design is assumed to increase and decrease a maximum of 6°F in one minute. The corresponding reactor coolant pressure variation is less than 100 psig. It is assumed that an infinite number of such fluctuations will occur.

12. Feedwater Cycling/Hot Standby - This transient assumes that a low steam generation rate is made up by intermittant (slug of water) feeding of 32 °F feedwater into the steam generator. For design purposes, 2000 occurrences are assumed over the life of the plant.

Rev. [LATER] ~~14 2/97~~

The techniques used to measure and predict the integrated fast neutron (E > 1 Mev) fluxes at the sample locations are described in Appendix 4A. The calculation method used to obtain the maximum neutron (E > 1 Mev) exposure of the reactor vessel is identical to that described for the irradiation samples. Since the neutron spectra at the sample can be applied with confidence to the adjacent section of reactor vessel, the maximum vessel exposure will be obtained from the measured sample exposure by appropriate application of the calculated azimuthal neutron flux variation.

The maximum integrated fast neutron (E>1 Mev) exposure of the vessel was computed to be 5.1 x 10^{19} n/cm^2 for 40 years of operation at 2300 Mwt at 80 percent load factor. After flux reduction was imposed in 1984 and after thermal uprating performed in 1995, the maximum vessel exposure at the limiting circumferential vessel weld is ~~preducted~~ predicted to be ~~2.74~~ 4.5 x 10^{19} n/cm^2 at the end of the extended license terms (~~29.5~~ 48 EFPY* approximately) (Reference 7). The predicted extended end of life RT(ndt) is less than the 10CFR50.61 screening criteria (Reference 6).

To evaluate the RT(ndt) shift of welds, heat affected zones and base material for the vessel, test coupons of these material types have been included in the reactor vessel surveillance program described in Section 4A.

* This value is approximate and will change from year to year based on the unit availability. Fluence prediction is acceptable in the ±20% range, so this value can easily vary within that limit.

4.2.13 REFERENCES

1. Westinghouse Electric Corporation, Report Number STC-TR-85-003 dated February 8, 1985, "Structural Evaluation - Pressurizer Surge Line and Spray Line for Pressurizer/RCS Differential Temperature of 320°F," PROPRIETARY.

2. Safety Evaluation, JPE-M-85-013, dated June 13, 1985, "Increased ΔT between Pressurizer and Reactor Coolant System to 320°F for PTP Unit 3."

3. NRC Letter, from G.E. Edison (NRC) to W.F. Conway (FPL), "Turkey Point Units 3 and 4 - Generic Letter 84-04, Asymmetric LOCA Loads," dated November 28, 1988.

4. NRC Letter, from R. P. Croteau (NRC) to J. H. Goldberg (FPL), "Turkey Point Units 3 and 4 - Approval to Utilize Leak-Before-Break Methodology for Reactor Coolant System Piping (TAC Nos. M91494 and M91495)," dated June 23, 1995.

5. Westinghouse WCAP-14237, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Turkey Point Units 3 and 4 Nuclear Power Plants," dated December 1994.

6. Westinghouse WCAP-14291, "Turkey Point Units 3 and 4 Uprating Engineering Report Volume 2," dated December, 1995.

7. Westinghouse WCAP-15092, Revision 3, "Turkey Point Units 3 and 4 WOG Reactor Vessel 60-Year Evaluation Minigroup Heatup and Cooldown Limit Curves for Normal Operation."

met is the more restrictive of a), the primary membrane stresses in the tube sheet ligaments, averaged across the ligament and through the tube sheet thickness, do not exceed 90% of the material yield stress at the operating temperature; or b), the primary membrane plus primary bending stress in the tube sheet ligaments, averaged across the ligament width at the tube sheet surface location giving maximum stress, do not exceed 135% of the material yield stress at operating temperature. This use of these stress criteria for this abnormal operation is consistent with the ASME Boiler and Pressure Vessel Code, Section III Nuclear Vessels, paragraph N 714.2 hydrotest stress criteria. The stresses and stress factors in the actual design tube sheet, obtained using the above stress criteria, are given in Table 4.3-3.

The tube sheet designed on the above basis meets code allowable stresses for a primary to secondary differential pressure of 1520 psi. The normal operating differential pressure is 1475 psi.

The tubes have been designed to the requirements (including stress limitations) of Section III for normal operation, assuming 2485 psi as the normal operating pressure differential. Hence, the secondary pressure loss accident condition imposes no extraordinary stress on the tubes beyond that normally expected and considered in Section III requirements.

No significant corrosion of the Inconel tubing is expected during the lifetime of the unit. The corrosion rate reported in Reference (4), (4) shows "worst case" rates of 15.9 mg/dm^2 in the 2000 hour test under steam generator operating conditions. Conversion of this rate to a ~~40~~ 60-year unit life gives a corrosion loss of less than ~~1.5~~ 2.25 x 10^{-3} inches which is insignificant compared to the nominal tube wall thickness of 0.050 inches.

In the case of a primary pressure loss accident, the secondary-primary pressure differential can reach 1100 psi. This pressure differential is less than the primary-secondary pressure differential capability

TABLE 4.4-2

SURVEILLANCE CAPSULE WITHDRAWAL SCHEDULE
TURKEY POINT UNITS 3 & 4

Capsule[4]	Capsule Location (Degree)	Updated Lead Factor	Removal EFPY[1]	Capsule Fluence (n/cm^2)
T_3[2]	270	2.60	1.15	7.39×10^{18}
T_4[2]	270	2.48	1.17	7.08×10^{18}
S_4[2]	280	1.60	3.41	1.43×10^{19}
S_3[2]	280	1.96	3.46	1.72×10^{19}
V_3[2]	290	0.75	8.06	1.53×10^{19}
X_3[3]	270	2.48	19.4 (29 years)	2.74×10^{19}
X_4[3]	270	2.48	24.0 (34 years)	3.85×10^{19}
Y_3	150	0.49	Standby	--
U_3	30	0.49	Standby	--
W_3	40	0.34	Standby	--
Z_3	230	0.34	Standby	--
V_4	290	0.79	Standby[5]	--
Y_4	150	0.49	Standby	--
U_4	30	0.49	Standby	--
W_4	40	0.34	Standby	--
Z_4	230	0.34	Standby	--

NOTES:

(1) Effective Full Power Years (EFPY) from plant startup.

(2) Plant specific evaluation.

(3) Since the vessel controlling material is the weld metal, and only Capsule V from Unit 4 and Capsules X from Units 3 and 4 contain weld specimens, Capsule X in Units 3 and 4 were moved to the 270° location to increase the lead factor.

(4) Unit designation shown in subscript.

(5) Standby end of life capsule, as needed.

Rev. [LATER] ~~14 2/97~~

UFSAR CHAPTER 5.0 CHANGES

5.1.3 CONTAINMENT DESIGN ANALYSES

This section discusses analytical techniques, references and design philosophy for the containment building design/analyses. The results of the original analyses and the 1994 re-analysis are provided in Section 5.1.4 and Appendix 5H, respectively. The original design criteria, analyses, and construction drawings have been reviewed by Bechtel's consultants, T. Y. Lin, Kulka, Yang & Associate.

Original Analysis

The original containment structure analyses fall into two parts, axisymmetric and non-axisymetric. The axisymmetric analysis is performed through the use of a finite element computer program for the individual loads and is described in Section 5.1.3.1. The axisymmetric finite element approximation of the containment structure shell does not consider the buttresses, penetrations, brackets and anchors. These items of configuration, and lateral loads due to earthquakes or winds, and any concentrated loads, are considered in the non-axisymmetric analysis described in Section 5.1.3.2.

1994 Re-analysis

During the performance of the 20th year tendon surveillance of the Turkey Point Units 3 and 4 containment structure post-tensioning systems, a number of measured normalized tendon lift-off forces were below the predicted lower limit (PLL). Evaluation of the 20th year surveillance results concluded that the probable cause for the low tendon lift-off forces was due to an increased tendon wire steel relaxation loss caused by average tendon temperatures higher than originally considered. The evaluations also concluded that the containment post-tensioning system will provide sufficient prestress force to maintain Turkey Point licensing basis requirements through the 25th year tendon surveillance. The evaluations recommended that a structural re-analysis of the containment structure be performed to determine the minimum required prestress forces, and to establish that the containment structure will continue to meet the licensing basis requirements through the end of the licensed plant 40-year life (see Appendix 5H for additional detail).

A containment structure re-analysis was completed in 1994 and Safety Evaluation JPN-PTN-SECJ-94-027 (Reference 9) has been performed to document the results of this re-analysis.

The containment re-analysis used a three dimensional (3-D) finite element model of the containment structure. The 3-D model consisted of the cylindrical wall (including buttresses), ring girder, dome, base slab, and the major penetrations (equipment hatch and personnel hatch). The containment re-analysis did not include a new evaluation of the base slab since it was not affected by the post-tensioning system. The base slab was included in the 3-D model to provide a realistic boundary condition for the model.

Appendix 5H provides a summary of the containment re-analysis methodology, analytical techniques, references, and results.

The portions of Sections 5.1.3 and 5.1.4 relative to the original analysis of the containment structure which are affected by the 1994 re-analysis (see Appendix 5H) are annotated in the pertinent sections.

<u>License Renewal Analysis</u>

<u>During the License Renewal process, the Turkey Point Units 3 and 4 containment tendons were analyzed for a 60-year life. The analysis concluded that the containment tendons will continue to meet the licensing basis requirements through the licensed plant 60-year life. (Subsection 16.3.4)</u>

5.1.3.1 <u>Axisymmetric Analysis</u> (original analysis)

The finite element technique is a general method of structural analysis in which the continuous structure is replaced by a system of elements (members) connected at a finite number of nodal points (joints). Standard conventional analysis of frames and trusses can be considered to be examples of the finite element method. In the application of the method to an axisymmetric solid (e.g., a concrete containment structure) the continuous structure is replaced by a system of rings of triangular cross-section which are interconnected along circumferential joints. Based on energy principles, work equilibrium equations are formed in which the radial and axial displacements at the circumferential joints are the unknowns. The results of the solution of this set of equations is the deformation of the structure under the given loading

5.1.3-1a Rev. <u>[LATER]</u> ~~13 10/96~~

Assuming that the jacking stress for the tendons is 0.80 f'_s or 192,000 psi and using the above prestress loss parameters, the following tabulation shows the magnitude of the design losses and the final effective prestress at end of 40 years for a typical dome, hoop, and vertical tendon.[(5)]

	Dome (Ksi)	Hoop (Ksi)	Vertical (Ksi)	Allowable (Ksi)
Temporary Jacking Stress	192	192	192	192
Friction Loss	19	21.3[(1)]	21	
Seating Loss	-	0	0	
Elastic Loss (average)	14.7	15.3	6.6	
Creep Loss	19.2	19.2	19.2[(4)]	
Shrinkage Loss	3.0	3.0	3.0	
Relaxation Loss[(3)]	12.5	12.5	12.5	
Final Effective Stress [(2)]	123.6	120.7	129.7	144.0

(1) Average of adjacent tendons

(2) This force does not include the effect of pressurization which increases the prestress force.

(3) See footnote (1) in listing at beginning of Section 5.1.4.4.

(4) To determine tendon surveillance lift-off acceptance criteria, the creep loss for the vertical tendons has been adjusted. For further details, see Reference 11 of safety evaluation JPN-PTN-SECJ-94-027 (Reference 9 on Page 5.1.3-38).

(5) The 40-year prestress losses depicted in the tabulation were utilized to calculate 60-year prestress losses for license renewal.

To provide assurance, of achievement of the desired level of Final Effective Prestress and that ACI 318-63 requirements are met, a written procedure was prepared for guidance of post-tensioning work. The procedures provided nominal values for end anchor forces in terms of pressure gage readings for calibrated jack-gage combinations. Force measurements were made at the end anchor, of course, since that is the only practical location for such measurements.

5.1.7.4 Tendon Surveillance

Provisions are made for an in-service tendon surveillance program, throughout the life of the plant that will maintain confidence in the integrity of the containment structure. ~~This program is supplemented by a corrosion control program.~~ (See Subsection 16.2.1.4 for program description relating to license renewal.)

The following quantity of tendons have been provided over and above the structural requirements:

Horizontal - Three 120 degree tendons comprising one complete hoop system.

Vertical - Three tendons spaced approximately 120 degrees apart.

Dome - Three tendons spaced approximately 120 degrees apart.

Beginning with the twentieth year tendon surveillance, inspections and lift-off readings are performed on five horizontal, four vertical, and three dome tendons. The tendons chosen for surveillance are a random but representative sample.

The surveillance program for structural integrity and corrosion protection consists of the following operations to be performed during each inspection:

(a) Lift-off readings will be taken for all of the twelve tendons.

(b) One tendon of each directional group will be relaxed and one wire from each relaxed tendon will be removed as samples for inspection. Since these tendons are re-tensioned to their original lift-off forces these samples need not be replaced.

(c) After the inspection, the tendons will be retensioned to the stress level measured at the lift-off reading and then checked by a final lift-off reading.

(d) Should the inspection of one of the wires reveal any significant corrosion (pitting, or loss of area), further inspection of the other two sets will be made to determine the extent of the corrosion and its significance to the load-carrying capacity of the structure. Samples of corroded wire will be tested to failure to evaluate the effects of any corrosion on the tensile strength of the wire.

The inspection of the four vertical tendons in the wall is sufficient to indicate any tendon corrosion that could possibly appear longitudinally along the full height of the structure. ~~Furthermore, the vertical tendons extend below the ground water table where corrosion is most likely to occur, if at all.~~ Therefore, the twelve tendons arranged as described will provide adequate corrosion surveillance.

The anchorage details permit some degree of accessibility for inspection of all tendons in the containment structure. Corrective action will be taken if and when so indicated by the surveillance program, and an adequate containment structure will be maintained throughout the life of the plant.

The following steps are taken to protect the tendons and the reinforcing steel in the containment structure from corrosion due to stray current and moisture environment.

A tendon protection sheathing filler compound encloses the whole length of every tendon. This compound will not deteriorate during the ~~forty-year~~ life of the unit. As its chemical composition is about 98% petroleum jelly, it will possess the normal stability of the linear hydrocarbons subjected to normal ambient temperature levels. The electrical resistivity of the compound is relatively high. This prevents the possibility of galvanic corrosion that would be detrimental to the tendons. Anodic corrosion centers that could develop on the surface of tendons surrounded by a good electrolyte material will not form in the presence of the protective sheathing filler.

All metallic components such as the tendon trumplate, reinforcing bars and liner plate are interconnected to form an electrically continuous cathodic structure, thereby avoiding inherent difficulties associated with isolation and interference of these members. This interconnection of the steel work with the liner plate ensures that cathodic protection currents will not be allowed to flow through any isolated member to cause electrolytic corrosion.

the combination of normal loads and design earthquake loading. Critical equipment needed for this purpose is required to operate within normal design limits.

In the case of the maximum hypothetical earthquake, it is only necessary to ensure that critical components do not lose their capability to perform their safety function, i.e., shut the unit down and maintain it in a safe condition. This capability is ensured by maintaining the stress limits as shown in Table 5A-1. No rupture of a Class I pipe is caused by the occurrence of the maximum hypothetical earthquake.

Careful design and thorough quality control during manufacture and construction and inspection during unit life, ensures that the independent occurrence of a reactor coolant pipe rupture is extremely remote. Leak-Before-Break (LBB) criteria has been applied to the reactor coolant system piping based on fracture mechanics technology and material toughness. That evaluation, together with the leak detection system, demonstrates that the dynamic effects of postulated primary loop pipe ruptures may be eliminated from the design basis (Reference 5A-2). This Leak-Before-Break evaluation was approved by the NRC for use at Turkey Point (Reference 5A-5). This evaluation has been revised for the period of extended operation, as discussed in Subsection 16.3.8.

5A-1.3.2.2 Reactor Vessel Internals

5A-1.3.2.2.1 Reactor Vessel Internals Design Criteria

The internals and core are designed for normal operating conditions and subjected to load of mechanical, hydraulic, and thermal origin. The response of the structure under the design earthquake is included in this category.

The stress criteria established in the ASME Boiler and Pressure Vessel Code, Section III, Article 4, have been adopted as a guide for the design of the internals and core with the exception of those fabrication techniques and materials which are not covered by the Code. Earthquake stresses are combined in the most conservative way and are considered primary stresses.

to accommodate the forces exerted by the restrained liner plate, and that careful attention be paid to details at corners and connections to minimize the effects of discontinuities.

The most appropriate basis for establishing allowable liner plate strains is considered to be that portion of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, Article 4. Specifically the following sections are adopted as guides in establishing the allowable strain limits:

Paragraph N 412 (m)	Thermal Stress
Paragraph N414.5	Peak Stress Intensity
	Table N 413
	Figure N 414, N 415 (A)
Paragraph N 412 (n)	
Paragraph N 415.1	

Implementation of the ASME Code requires that the liner material be prevented from experiencing significant distortion due to thermal load and that the stresses be considered from a fatigue standpoint. (Paragraph N412 (m) (2)).

The following fatigue loads are considered in the 60-year design analysis of the liner plate (See Subsection 16.3.5 for additional details):

(a) Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is ~~40~~ 60 cycles for the unit life of ~~40~~ 60 years.

(b) Thermal cycling due to the containment interior temperature variation during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500 cycles.

(c) Thermal cycling due to the MHA will be assumed to be one cycle.

(d) Thermal load cycles in the piping systems are somewhat isolated from the liner plate penetrations by the concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Section III fatigue considerations. All penetrations are reviewed for a conservative number of cycles to be expected during the 60-year unit life.

The thermal stresses in the liner plate fall into the categories considered in Article 4, Section III, of the ASME Boiler and Pressure Vessel Code. The allowable stresses in Figure N-415 (A) are for alternating stress intensity for carbon steel and temperatures not exceeding 700°F.

In accordance with ASME Code Paragraph N412 (m) 2, the liner plate is restrained against significant distortion by continuous angle anchors and never exceeds the temperature limitation of 700°F and also satisfies the criteria for limiting strains on the basis of fatigue consideration. Paragraph N412 (n) Figure N-415 (A) of the ASME Code has been developed as a result of research, industry experience, and the proven performance of code vessels, and it is a part of recognized design code. Figure N-415 (A) and its appropriate limitations have been used as a basis for establishing allowable liner plate strains. Since the graph in Figure N-415 (A) does not extend below 10 cycles, 10 cycles is being used for MHA instead of one cycle.

The maximum compressive strains are caused by accident pressure, thermal loading prestress, shrinkage and creep. The maximum strains do not exceed .0025 in/in and the liner plate always remains in a stable condition.

UFSAR CHAPTER 6.0 CHANGES

Testing of Operational Sequence of Air Cleanup Systems

Criterion: A capability shall be provided to test initially under conditions as close to design as practical, the full operational sequence that would bring the air cleanup systems into action, including the transfer to alternate power sources and the design air flow delivery capability. (GDC 65)

Means are provided to test initially under conditions as close to design as is practical, the full operational sequence that would bring the Emergency Containment Filtering System into action, including transfer to the emergency diesel-generator power source.

6.3.6 MOTORS FOR EMERGENCY CONTAINMENT FANS

General

These totally enclosed fan cooled motors will have a useful life of ~~forty (40)~~ sixty (60) years under the normal containment service conditions as demonstrated by the appropriate EQ documentation package (See Appendix 8A). Internal heaters will dispel moisture condensation when motor is idle.

Insulation

The insulation will be a special Class B suitable for MHA conditions. The insulation system is described in Table 6.3-2.

Bearings

The bearings will be specially selected, conservatively rated ball bearings

6.3-13 Rev. [LATER]

UFSAR CHAPTER 8.0 CHANGES

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 based on EPRI NP-2129. However, certain solid state electronic components and components that utilize teflon are considered to be in a mild environment only if total radiation dose is 1.0E3 rads or less.

For additional detail on the identification of environmental conditions refer to Equipment Qualification Documentation Package (Doc Pac) 1001, "Generic Approach and Treatment of Issues."

8A.5 MAINTENANCE

The purpose of the Turkey Point Equipment Qualification Maintenance Program is the preservation of the qualification of systems, structures and components. In order to accomplish this task, the plants have developed approved Design Control, Procurement and Maintenance Procedures. In addition, the component specific documentation package contains the equipment's qualified life. The qualified life is developed based upon the qualification test report reviewed in conjunction with the environmental parameters associated with the area. After this review is completed a qualified life is established. Maintenance activities to be performed in addition to the vendor recommended maintenance are determined to ensure that qualification of each piece of equipment is maintained throughout its qualified life.

8A.6 RECORDS/QUALITY ASSURANCE

A documentation package is prepared for the qualification of each manufacturer's 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 as defined in 10CFR50.49 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 Doc Pac 1001.

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

UFSAR CHAPTER 9.0
CHANGES

TABLE 9.2-2

NOMINAL CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE (1)

Unit design life, years	~~40~~ 60
Seal water supply flow rate, gpm (2)	24
Seal water return flow rate, gpm	9
Normal letdown flow rate, gpm	60
Maximum letdown flow rate, gpm	120
Normal charging pump flow (one pump), gpm	69
Normal charging line flow, gpm	45
Maximum rate of boration with one transfer and one charging pump from an initital RCS concentration of 1800 ppm, ppm/min	5.4
Equivalent cooldown rate to above rate of boration, °F/min	1.5
Maximum rate of boron dilution with two charging pumps from an initial RCS concentration of 2500 ppm, ppm/hour	350
Two-pump rate of boration, using refueling water, from initial RCS concentration of 10 ppm, ppm/min	6.2
Equivalent cooldown rate to above rate of boration, °F/min	1.7
Temperature of reactor coolant entering system at full power (design), °F	555.0
Temperature of coolant return to reactor coolant system at full power (design), °F	493.0
Normal coolant discharge temperature to holdup tanks, °F	127.0
Amount of 3.0 weight percent boron solution required to meet cold shutdown requirements, at end of life with peak xenon (including consideration for one stuck rod) gallons	7500

NOTES :

1. Reactor coolant water quality is given in Table 4.2-2.
2. Volumetric flow rates in gpm are based on 130°F and 2350 psig.

Rev. [LATER] ~~10 7/92~~

UFSAR CHAPTER 11.0 CHANGES

TABLE 11.1-1

WASTE DISPOSAL SYSTEM
PERFORMANCE DATA
(Two Units)

Plant Design Life	~~40~~ 60 years
Normal process capacity, liquids	Table 11.1-3
Evaporator load factor	Table 11.1-4
Annual liquid discharge	
Volume	Table 11.1-4
Activity	
Tritium	Table 11.1-5
Other	Table 11.1-5
Annual gaseous discharge	
Activity	Table 11.1-6

Rev. [LATER]

UFSAR CHAPTER 14.0 CHANGES

The neutron absorber rack design includes a poison verification view-hole in the cell wall so that the presence of poison material may be visually confirmed at any time over the life of the racks. Upon completion of rack fabrication, such an inspection was performed. This visual inspection, coupled with the Westinghouse quality assurance program controls and the use of qualified Boraflex neutron absorbing material, satisfies an initial verification test to assure that the proper quantity and placement of material was achieved during fabrication of the racks. This precludes the necessity for on-site poison verification.

As discussed in Section 4.7.2, irradiation tests have been previously performed to test the stability and structural integrity of Boraflex in boric acid solution under irradiation[7]. These tests have concluded that there is no evidence of deterioration of the suitability of the Boraflex poison material through a cumulative irradiation in excess of 1 x 10^{11} rads gamma radiation. As more data on the service life performance of Boraflex becomes available in the nuclear industry in the coming years through both experimentation and operating experience, FPL will evaluate this information and will take action accordingly. (See Subsection 16.2.2 for a program description relating to License Renewal.)

[NEW]
UFSAR CHAPTER 16.0

[NEW CHAPTER 16]

16.0 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 that 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 Turkey Point.

16.1 NEW PROGRAMS

16.1.1 AUXILIARY FEEDWATER PUMP OIL COOLERS INSPECTION

The cast iron parts of the auxiliary feedwater pumps lube oil coolers and turbine governor controller oil coolers, which are wetted internally by auxiliary feedwater, are potentially susceptible to graphitic corrosion (i.e., selective leaching) and other types of corrosion. A one-time visual inspection will be performed on one of the cast iron bonnets of the auxiliary feedwater pump lube oil coolers to assess the extent of loss of material due to corrosion. The results of this inspection will be evaluated to determine the need for additional inspections/programmatic corrective actions. This inspection and evaluation will be implemented prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.1.2 AUXILIARY FEEDWATER STEAM PIPING INSPECTION PROGRAM

The Auxiliary Feedwater Steam Piping Inspection Program manages the aging effects of loss of material due to general and pitting corrosion on the internal and external surfaces of carbon steel auxiliary feedwater steam supply lines. Periodic volumetric examinations of representative auxiliary feedwater steam supply components will be performed to ensure that minimum required wall thickness is maintained. Examinations will be performed on piping/fittings and other components using volumetric techniques, such as ultrasonic or computed radiography. The inspections will be implemented prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.1.3 EMERGENCY CONTAINMENT COOLERS INSPECTION

A one-time volumetric examination of a sample of emergency containment coolers (ECC) tubes will be performed to determine the extent of loss of material due to erosion in the ECC tubes. The results of this inspection will be evaluated to determine the need for additional inspections/programmatic corrective actions. This inspection and evaluation will be implemented prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.1.4 FIELD ERECTED TANKS INTERNAL INSPECTION

A one-time visual inspection to determine the extent of corrosion on the internal surfaces of the field erected tanks for both units -- including the Condensate Storage Tanks, the Demineralized Water Storage Tank, and the Refueling Water Storage Tanks -- will be performed. The results of these inspections will be evaluated to determine the need for additional inspections/programmatic corrective actions. These inspections will be implemented prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.1.5 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 internal surfaces of susceptible piping and components. The program involves selected, one-time inspections on the internal surfaces of piping and components with the greatest susceptibility to galvanic corrosion. Loss of material is expected mainly in carbon steel components directly coupled to stainless steel components in raw water systems, however, 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 followup examinations or programmatic corrective actions will be established. The program will be implemented prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.1.6 REACTOR VESSEL INTERNALS INSPECTION PROGRAM

The Reactor Vessel Internals Inspection Program consists of two types of examinations, visual and ultrasonic testing. The visual examination manages the aging effect of cracking due to irradiation assisted stress corrosion (IASCC) and reduction in fracture toughness due to irradiation and thermal embrittlement. The ultrasonic testing examination manages the aging effect of loss of mechanical closure integrity of reactor vessel internals bolting. The program, including an evaluation of program scope with regard to dimensional changes due to void swelling, will be in place prior to the end of the initial operating license terms for Turkey Point Units 3 and 4, and the actual visual and ultrasonic examinations, one inspection per unit, will be performed during the period of extended operation.

16.1.7 SMALL BORE CLASS 1 PIPING INSPECTION

A volumetric inspection of a sample of small bore Class 1 piping and nozzles 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. The inspection will be performed prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2 EXISTING PROGRAMS

16.2.1 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

16.2.1.1 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, and loss of mechanical closure integrity. The program provides inspection and examination of accessible components, including welds, pump casings, valve bodies, steam generator tubing, and pressure-retaining bolting.

16.2.1.2 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 and the metallic liner of Class CC pressure-retaining components and their integral attachments. The program manages the aging effects of loss of material and loss of pressure retention. The program provides inspection and examination of containment surfaces, seals, gaskets and moisture barriers, pressure-retaining bolting, and pressure retaining components in accordance with the requirements of ASME Section XI, Subsection IWE.

16.2.1.3 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.

16.2.1.4 ASME SECTION XI, SUBSECTION IWL INSERVICE INSPECTION PROGRAM

ASME Section XI, Subsection IWL Inservice Inspection Program inspections assess the quality and structural performance of the Containment structure post-tensioning system components. The program manages the aging effects of loss of material and confirms the results of the Containment tendon loss of prestress Time-Limited Aging Analysis (see Subsection 16.3.4). The program includes inspection of tendon and anchorage hardware surfaces and measurement of tendon force and elongation.

16.2.2 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 provide for density testing (or other approved testing methods if available) of the encapsulated Boraflex material in the spent fuel storage racks prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.3 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

The Boric Acid Wastage Surveillance Program manages the aging effects of loss of material and mechanical closure integrity due to aggressive chemical attack resulting from borated water leaks. The program addresses the Reactor Coolant System 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 pressure boundary or structural integrity of components, supports, or structures, including electrical equipment in proximity to borated water systems. This program includes commitments to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

Some systems outside Containment (i.e., Spent Fuel Pool Cooling and portions of Waste Disposal associated with containment integrity) are currently inspected under other existing programs. The scope of the Boric Acid Wastage Surveillance Program will be enhanced to include these systems and components prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.4 CHEMISTRY CONTROL PROGRAM

The Chemistry Control Program manages loss of material, cracking, and fouling aging effects for primary and secondary 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 mechanisms. The program includes sampling activities and analysis. The program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems, structures, and components covered by the program, and thus prevents and minimizes the occurrences of aging effects.

16.2.5 CONTAINMENT SPRAY SYSTEM PIPING INSPECTION PROGRAM

The Containment Spray System Piping Inspection Program manages the aging effect loss of material due to general, crevice, and pitting corrosion on the internal surfaces of carbon steel piping and fittings, and valves wetted by boric acid in the Containment Spray System spray headers. Periodic ultrasonic examinations of selected locations are used to determine wall thickness and are evaluated to ensure that minimum thickness requirements are maintained.

16.2.6 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification 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 the same as 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.

16.2.7 FATIGUE MONITORING PROGRAM

The Fatigue Monitoring Program is designed to track design cycles to ensure that Reactor Coolant System components remain within their design fatigue limits. Design cycle limits for Turkey Point Units 3 and 4 are provided in Table 4.1-8. The specific fatigue analyses validated by the Fatigue Monitoring Program are associated with the reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines. Administrative procedures provide the methodology for logging design cycles. Guidance is provided in the event design cycle limits are approached.

16.2.8 FIRE PROTECTION PROGRAM

The Fire Protection Program manages the aging effects of loss of material, cracking, and fouling for the components/piping of the Fire Protection System and Fire Rated Assemblies. Additionally, this program manages the aging effects of loss of material, loss of seal, cracking, and erosion for structures and structural components associated with fire protection. Appendix 9.6A contains a detailed discussion of the Fire Protection Program.

The scope of the Fire Protection Program will be enhanced to include inspection of additional components prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.9 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 wear in high energy carbon steel piping associated with the Main Steam and Turbine Generators, and 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.

This program will be enhanced to address internal and external loss of material of steam trap lines due to flow accelerated corrosion and general corrosion, respectively, prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.10 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, stress corrosion cracking, and biological fouling for Intake Cooling Water System components. The program includes inspections, performance testing, evaluations, and corrective actions that are performed as the result of FPL commitments to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

This program will be enhanced to improve documentation of scope and frequency of the intake cooling water piping crawl-through inspections and component cooling water heat exchanger tube integrity inspections prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.11 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE PROGRAM

The Periodic Surveillance and Preventive Maintenance Program manages the aging effects of loss of material, cracking, fouling buildup, loss of seal, and embrittlement for systems, structures, and components. The scope of the program provides for visual inspection and examination of selected surfaces of specific components and structural components. The program also includes leak inspection of limited portions of the Chemical and Volume Control Systems. Additionally, the program provides for replacement/refurbishment of selected components on a specified frequency, as appropriate.

Specific enhancements to the scope and documentation of some inspections performed under this program will be implemented prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.12 REACTOR VESSEL HEAD ALLOY 600 PENETRATION INSPECTION PROGRAM

The Reactor Vessel Head Alloy 600 Penetration Inspection Program encompasses the Turkey Point Units 3 and 4 reactor vessel head Alloy 600 penetrations that are part of the Reactor Coolant System pressure boundary. This program manages the aging effect of cracking due to primary water stress corrosion (PWSCC). The program includes a one-time volumetric examination of selected Unit 4 reactor vessel head penetrations to detect crack initiation. Visual examination of the Unit 3 and Unit 4 reactor vessel head external surfaces during outages and the Boric Acid Wastage Surveillance Program are also utilized to manage cracking.

16.2.13 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 all aspects of the Reactor Vessel Integrity Program prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.13.1 REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION

This subprogram manages the aging effect of reduction in fracture toughness of the Turkey Point Units 3 and 4 reactor vessel materials (beltline forgings and circumferential 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 a

NRC-approved program that meets the requirements of 10 CFR 50, Appendix H. The surveillance capsule withdrawal schedule is specified in Table 4.4-2.

16.2.13.2 FLUENCE AND UNCERTAINTY CALCULATIONS

This subprogram provides an accurate prediction of the Turkey Point Units 3 and 4 reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline forgings and circumferential welds.

16.2.13.3 MONITORING EFFECTIVE FULL POWER YEARS

This subprogram accurately monitors and tabulates the accumulated operating time experienced by the reactor vessels to ensure that the Turkey Point Units 3 and 4 pressure-temperature limit curves and end-of-life reference temperatures are not exceeded.

16.2.13.4 PRESSURE-TEMPERATURE LIMIT CURVES

This subprogram provides pressure-temperature limit curves for the Turkey Point Units 3 and 4 reactor vessels to establish the Reactor Coolant System operating limits. The pressure-temperature limit curves are included in the Technical Specifications.

16.2.14 STEAM GENERATOR INTEGRITY PROGRAM

The Steam Generator Integrity Program ensures 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 and includes the following essential elements:

- Inspection of steam generator tubing and tube plugs
- Steam generator secondary-side integrity inspections
- Tube integrity assessments
- Assessment of degradation mechanisms
- Primary-to-secondary leakage monitoring
- Primary and secondary chemistry control
- Sludge lancing
- Maintenance and repairs

- Foreign material exclusion

16.2.15 SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling, 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 by restructuring it to address inspection requirements to manage certain aging effects in accordance with 10 CFR 54, modifying the scope of specific inspections, and improving documentation requirements prior to the end of the initial operating license terms for Turkey Point Units 3 and 4.

16.2.16 THIMBLE TUBE INSPECTION PROGRAM

The Thimble Tube Inspection Program manages the aging effect of material loss due to fretting wear. This program consists of an eddy current test inspection of thimble tube N-05 on Unit 3. Eddy current testing of thimble tubes was initiated in response to NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," and inspections have been performed on all in-service thimble tubes for Units 3 and 4. This inspection will be performed prior to the end of the initial operating license term for Turkey Point Unit 3.

16.3 TIME-LIMITED AGING ANALYSIS ACTIVITIES

16.3.1 REACTOR VESSEL IRRADIATION EMBRITTLEMENT

The Turkey Point Units 3 and 4 reactor vessels are described in Chapters 3.0 and 4.0. Time-limited aging analyses (TLAAs) applicable to the reactor vessels are:

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

The Reactor Vessel Integrity Program, described in Subsection 16.2.13, 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 limit curves to ensure continuing vessel integrity through the period of extended operation.

16.3.1.1 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 at the end of the extended period of operation (48 effective full power years) for the Turkey Point Units 3 and 4 reactor vessels 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 Turkey Point reactor vessels 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).

16.3.1.2 UPPER-SHELF ENERGY

The requirements on reactor vessel Charpy upper-shelf energy 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 upper-shelf energy of any reactor vessel material is predicted to drop below 50 ft-lb., as measured by Charpy V-notch specimen testing.

A fracture mechanics evaluation was performed in accordance with Appendix K of ASME Section XI to demonstrate continued acceptable equivalent margins of safety against fracture through 48 effective full power years.

The analysis associated with upper-shelf energy 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).

16.3.1.3 PRESSURE-TEMPERATURE LIMITS

The requirements in 10 CFR 50, Appendix G, ensure that heatup and cooldown of the reactor pressure vessel are 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. Operation of the Reactor Coolant System is also limited by the net positive suction curves for the reactor coolant pumps. These curves specify the minimum pressure required to operate the reactor coolant pumps. Therefore, in order to heatup and cooldown, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G pressure-temperature limits and the net positive suction curves.

To address the period of extended operation, the 48 effective full power year projected fluences and the Turkey Point-specific reactor vessel material properties were used to determine the limiting material and calculate pressure-temperature limits for heatup and cooldown. The limiting material at all temperatures for the period of extended operation is the circumferential girth weld.

A license amendment to incorporate the pressure-temperature limit curves projected to 48 effective full power years will be submitted to the NRC for review and approval prior to exceeding the licensed operating period for these curves.

The analysis associated with reactor vessel pressure-temperature limit curves has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.2 METAL FATIGUE

The thermal and mechanical fatigue analyses of plant mechanical components have been identified as time-limited aging analyses for Turkey Point. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the Turkey Point UFSAR.

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

The reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines have been designed in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class 1. The ASME Boiler and Pressure Vessel Code, Section III, Class 1 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 Turkey Point Units 3 and 4 Nuclear Steam Supply System components were determined using design cycles that were specified in the plant design process. 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 various Nuclear Steam Supply System components satisfying ASME fatigue usage design requirements, and became part of the plant Technical Specifications.

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 cycle set applicable to the Class 1 components was assembled. The actual frequency of occurrence for the design cycles was determined and compared to the design cycle set. The severity of the actual plant transients was compared to the severity of the design cycles. This comparison was performed in order to demonstrate that on an event-by-event basis, the design cycle profiles envelop actual plant operation. In addition, a review of the applicable administrative and operating procedures was performed to verify the effectiveness of the current design cycle counting program.

This review 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 reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines have been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

As a confirmatory program, the monitoring of plant transients performed as a part of the Fatigue Monitoring Program, as described in Subsection 16.2.7, will assure that the design cycle limits are not exceeded.

16.3.2.2 REACTOR VESSEL UNDERCLAD CRACKING

In early 1971, an anomaly identified as grain boundary separation, perpendicular to the direction of the cladding weld overlay, was identified in the heat-affected zone of reactor vessel base metal. A generic fracture mechanics evaluation demonstrated that the growth of underclad cracks during a 40-year plant life is insignificant.

The evaluation was extended to 60 years using fracture mechanics evaluations based on a representative set of design transients with the occurrences extrapolated to cover 60 years of service life. The 60-year evaluation shows insignificant growth of the underclad cracks.

The analysis associated with reactor vessel underclad crack growth has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

16.3.2.3 REACTOR COOLANT PUMP FLYWHEEL

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions which may result in overspeed of the reactor coolant pump increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway. An evaluation of the probability of failure over the extended period of operation was performed. It demonstrates that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life.

The analysis associated with the structural integrity of the reactor coolant pump flywheel has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

16.3.2.4 ANSI B31.1 PIPING

The Reactor Coolant System primary loop piping and balance-of-plant piping are designed to the requirements of ANSI B31.1, Power Piping. The exceptions are the Units 3 and 4 pressurizer surge lines and the Unit 4 Emergency Diesel Generator safety-related piping.

The pressurizer surge lines have been designed to the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class 1.

The Unit 4 Emergency Diesel Generator safety-related piping has been designed to the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class 3, which is essentially the same as ANSI B31.1 design requirements. The evaluation of the Unit 4 Emergency Diesel Generator safety-related piping fatigue is, therefore, included in the discussion below.

Design requirements in ANSI B31.1 assume a stress range reduction factor to provide conservatism in the piping design to account for fatigue due to thermal cyclic operation. This reduction factor is 1.0 provided the number of anticipated cycles is limited to 7000 equivalent full temperature cycles. 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. Considering this limit, a review of the ANSI B31.1 piping within the scope of license renewal was performed in order to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping systems within the scope of license renewal are only occasionally subject to cyclic operation. Typically these systems are subject to continuous steady-state operation and vary operating temperatures only during plant heatup and cooldown, during plant transients, or during periodic testing. The results of the evaluation for ANSI B31.1 piping systems demonstrate that the number of assumed thermal cycles would not be exceeded in 60 years of plant operation.

The analyses associated with ANSI B31.1 piping 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).

16.3.2.5 ENVIRONMENTALLY ASSISTED FATIGUE

The Turkey Point 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 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, especially the early-vintage Westinghouse PWR calculations, are directly relevant to Turkey Point. The description of the "Older Vintage Westinghouse Plant" evaluated in NUREG/CR-6260 matches Turkey Point with respect to design code. In addition, the transient cycles considered in the evaluation match or bound Turkey Point design.

NUREG/CR-6260 calculated fatigue usage factors for critical fatigue-sensitive component locations for the early-vintage Westinghouse plant utilizing the interim fatigue curves provided in NUREG/CR-5999, "Interim Fatigue Design Curves for Carbon, Low-Alloy, and Austenitic Stainless Steels in LWR Environments," August 1993. The results of NUREG/CR-6260 analyses were then utilized to scale up the Turkey Point plant-specific usage factors for the same locations to account for environmental effects. Generic industry studies performed by EPRI and NEI were also considered in this aspect of the evaluation, as well as environmental data that have been collected and published subsequent to the generic industry studies. Based on these adjustments, only the pressurizer surge line piping required further evaluation for the period of extended operation.

In lieu of additional analyses to refine the usage factor for the pressurizer surge lines, Turkey Point has selected aging management to address pressurizer surge line fatigue during the period of extended operation. In particular, the potential for crack initiation and growth, including reactor water environmental effects, will be managed by the Turkey Point ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, as described in Subsection 16.2.1.1.

16.3.3 ENVIRONMENTAL QUALIFICATION

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

Equipment included in the Turkey Point 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 the same as for equipment currently qualified at Turkey Point 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 16.2.6.

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)(i), or have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

16.3.4 CONTAINMENT TENDON LOSS OF PRESTRESS

The Turkey Point Units 3 and 4 containment buildings are post-tensioned, reinforced concrete structures composed of vertical cylinder walls and a shallow dome, supported on a conventional reinforced concrete base slab. The cylinder walls are provided with vertical tendons and horizontal hoop tendons. The dome is provided with three groups of tendons oriented 120-degrees apart.

The prestress of containment tendons decreases over time as a result of seating of anchorage losses, elastic shortening of concrete, creep of concrete, shrinkage of concrete, relaxation of prestressing steel, and friction losses. New upper limit curves, lower limit curves, and trend lines of measured prestressing forces have been established for all tendons through the period of extended operation. The predicted final effective preload at the end of 60 years exceeds the minimum required preload for all containment tendons. Consequently, the post-tensioning system will continue to perform its intended function throughout the period of extended operation.

The analyses associated with containment tendon loss of prestress have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

As a confirmatory program, the Containment structure post-tensioning system surveillance performed as a part of the ASME Section XI, Subsection IWL Inservice Inspection Program, as described in Subsection 16.2.1.4, will continue to be performed in accordance with the requirements of plant Technical Specifications.

16.3.5 CONTAINMENT LINER PLATE FATIGUE

The interior surface of each Containment is lined with welded steel plate to provide an essentially leak-tight barrier. Design criteria are applied to the liner to assure that the specified allowed leak rate is not exceeded under the design basis accident conditions. The fatigue loads, as described in Appendix 5B, Section B.2.1, were considered in the design of the liner plates and are considered time-limited aging analyses for the purposes of license renewal. Each of these has been evaluated for the period of extended operation.

The number of thermal cycles due to annual outdoor temperature variations was increased from 40 to 60 for the extended period of operation. The effect of this increase is insignificant in comparison to the assumed 500 thermal cycles due to Containment interior temperature varying during heatup and cooldown of the Reactor Coolant System. The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 Reactor Coolant System allowable design heatup and cooldown cycles, which is sufficient margin to accommodate the additional 20 cycles of annual outdoor temperature variation. Therefore, this loading condition is considered valid for the period of extended operation as it is enveloped by the evaluation for 500 thermal cycles.

The assumed 500 thermal cycles was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the Reactor Coolant System. The Reactor Coolant System was designed to withstand 200 heatup and cooldown thermal cycles. The evaluation determined that the originally projected number of maximum Reactor Coolant System design cycles is conservative enough to envelop the projected cycles for the extended period of operation. Therefore, the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the period of extended operation.

The assumed value of one for thermal cycling due to the maximum hypothetical accident remains valid. No maximum hypothetical accident has occurred and none is expected, therefore, this assumption is considered valid for the period of extended operation.

The design of the containment penetrations has been reviewed. The design meets the general requirements of the 1965 Edition of ASME Boiler and Pressure Vessel Code, Section III. The main steam piping, feedwater piping, blowdown piping, and letdown piping are the only piping penetrating the containment wall and liner plate that contribute significant thermal loading on the liner plate. The projected number of actual operating cycles for these piping systems through 60 years of operation was determined to be less than the original design limits.

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

16.3.6 BOTTOM MOUNTED INSTRUMENTATION THIMBLE TUBE WEAR

As discussed in NRC Information Notice No. 87-44, Supplement 1, "Thimble Tube Thinning in Westinghouse Reactors," thimble tubes have experienced thinning as a result of flow-induced vibration. Thimble tube wear results in degradation of the Reactor Coolant System pressure boundary and could potentially create a non-isolable leak of reactor coolant. Therefore, the NRC staff requested that licensees perform the actions described in NRC Bulletin No. 88-09, "Thimble Tube Thinning in Westinghouse Reactors." In response to this bulletin, FPL established a program for inspection and assessment of thimble tube thinning. Turkey Point commitments to the NRC for two eddy current inspections of the thimble tubes for each unit were completed in May 1990 for Unit 4, and in December 1992 for Unit 3. The results demonstrated that the thimble tubes were acceptable for operation and that no appreciable thinning had occurred between the two inspections. Based on the results of the inspections and the analyses performed, only the Unit 3 thimble tube N-05 will require further evaluation for the extended period of operation.

In order to ensure thimble tube reliability, an inspection of Unit 3 thimble tube N-05 will be conducted under the Thimble Tube Inspection Program, described in Subsection 16.2.16. This aging management program will ensure that thimble tube thinning will be adequately managed for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

16.3.7 EMERGENCY CONTAINMENT COOLER TUBE WEAR

The component cooling water flow rate through the emergency containment coolers could exceed the nominal design flow during certain plant conditions. High flow rates can produce increased wear on the inside surface of the emergency containment cooler tubes. The effect of increased wear was previously evaluated and the tube wall nominal thickness was determined to exceed the minimum required wall thickness during the existing operating period of 40 years. In order to ensure emergency containment cooler tube reliability, a one-time inspection for minimum tube wall thickness will be conducted on a sample of cooler tubes prior to the end of the existing operating period to further assess the actual tube wall thinning. The inspection will be conducted in accordance with the Emergency Containment Coolers Inspection, described in Subsection 16.1.3.

The Emergency Containment Coolers Inspection will ensure that the aging effect of emergency containment cooler tube wear will be adequately managed for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

16.3.8 LEAK-BEFORE-BREAK FOR REACTOR COOLANT SYSTEM PIPING

A plant-specific Leak-Before-Break (LBB) analysis was performed for Turkey Point Units 3 and 4 in 1994. The LBB analysis was performed to show that any potential leaks that develop in the Reactor Coolant System 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 June 23, 1995, NRC letter to FPL (Appendix 5A, Reference 5A-5), the NRC approved the Turkey Point LBB analysis. The NRC safety evaluation concluded that the LBB analysis was consistent with the criteria in NUREG-1061, Volume 3, and the draft Standard Review Plan, Section 3.6.3; therefore, the analysis complied with GDC-4.

The LBB analysis for Turkey Point was revised to address the extended period of operation utilizing criteria consistent with the requirements of NUREG-1061, Volume 3, and the draft Standard Review Plan, Section 3.6.3, that the NRC had referenced in their approval of the original LBB analysis. Since the primary loop piping includes cast stainless steel fittings, fully aged fracture toughness properties were determined for each heat of material. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were postulated at the critical locations that would cause leakage at a rate ten times the leakage detection system capability. Including the requirement for margin of applied loads, large margins against flaw instability were demonstrated for the postulated flaw sizes.

Finally, a plant-specific fatigue crack growth analysis for Turkey Point Units 3 and 4 for a 60-year plant life was performed. A design transient set that bounds the Turkey Point design transients was utilized in the fatigue crack growth analysis. Fatigue crack growth for the period of extended operation is negligible.

The Reactor Coolant System primary loop piping Leak-Before-Break 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).

16.3.9 CRANE LOAD CYCLE LIMIT

The crane load cycle limit was identified as a time-limited aging analysis for the cranes within the scope of license renewal. They include the polar cranes, reactor cavity manipulator cranes, spent fuel pool bridge cranes, spent fuel cask crane, turbine gantry crane, and intake structure bridge crane.

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).

APPENDIX B

AGING MANAGEMENT PROGRAMS

TABLE OF CONTENTS

1.0 INTRODUCTION

The Turkey Point Integrated Plant Assessment comprises four major activities, consistent with the draft 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 Turkey Point 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. 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 current licensing basis 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-2], Sections 4.2 and 4.3, served as the primary input to the attribute definitions used in this appendix.

Two attributes common to all programs discussed in this appendix are Corrective Actions and Administrative Controls. They are described as follows:

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.

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.

Corrective Actions and Administrative Controls apply to aging management programs credited for license renewal and performed, or in the case of new programs to be performed, in accordance with the FPL Quality Assurance Program. Accordingly, discussion of Corrective Actions and Administrative Controls is not included in the summary descriptions of the individual programs in this appendix.

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 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 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 for license renewal.

New Aging Management Programs

- Auxiliary Feedwater Pump Oil Coolers Inspection
- Auxiliary Feedwater Steam Piping Inspection Program
- Emergency Containment Coolers Inspection
- Field Erected Tanks Internal Inspection
- Galvanic Corrosion Susceptibility Inspection Program
- Reactor Vessel Internals Inspection Program
  - Visual Examination
  - Ultrasonic Examination
- Small Bore Class 1 Piping Inspection

Existing Aging Management Programs

- ASME Section XI Inservice Inspection Programs
  - ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
  - ASME Section XI, Subsection IWE Inservice Inspection Program
  - ASME Section XI, Subsection IWF Inservice Inspection Program
  - ASME Section XI, Subsection IWL Inservice Inspection Program
- Boraflex Surveillance Program
- Boric Acid Wastage Surveillance Program
- Chemistry Control Program
- Containment Spray System Piping Inspection Program
- Environmental Qualification Program
- Fatigue Monitoring Program
- Fire Protection Program

- Flow Accelerated Corrosion Program
- Intake Cooling Water System Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Reactor Vessel Head Alloy 600 Penetration Inspection Program
- Reactor Vessel Integrity Program
    - Reactor Vessel Surveillance Capsule Removal and Evaluation
    - Fluence and Uncertainty Calculations
    - Monitoring Effective Full Power Years
    - Pressure-Temperature Limit Curves
- Steam Generator Integrity Program
- Systems and Structures Monitoring Program
- Thimble Tube Inspection 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 AUXILIARY FEEDWATER PUMP OIL COOLERS INSPECTION

As identified in Chapter 3, the Auxiliary Feedwater Pumps Oil Coolers Inspection is credited for aging management of the auxiliary feedwater pumps in Auxiliary Feedwater and Condensate Storage.

Scope

This inspection is intended to be a one-time inspection of an oil cooler of one of the three shared auxiliary feedwater pumps. The Auxiliary Feedwater Pump Oil Coolers Inspection will manage the effects of loss of material due to graphitic corrosion (i.e., selective leaching) and other types of corrosion of the internal surfaces of cast iron parts of the oil coolers wetted internally by treated water – secondary. A visual inspection will be performed to detect loss of material. The inspection will include the cast iron bonnet of one of the auxiliary feedwater pump lube oil coolers and, if necessary, the cast iron parts of an auxiliary feedwater turbine governor controller oil cooler. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

No preventive actions are applicable to this inspection.

Parameters Monitored or Inspected

The Auxiliary Feedwater Pump Oil Coolers Inspection will identify the presence of graphitic corrosion activity and will quantify the loss of structurally sound wall thickness of cast iron parts. The inspection will consist of two parts, an "as found" inspection of parts and an inspection of parts after light sandblasting to bare metal.

Detection of Aging Effects

Visual inspection will be used to verify whether graphitic corrosion has taken place. The aging effect of concern, loss of material due to graphitic corrosion and other types of corrosion, will be further evident by the reduced wall thickness of structurally sound material in the cast iron parts being examined (following the sandblasting).

Monitoring and Trending

As stated above, this inspection is intended to be a one-time inspection of one cooler. If significant loss of material due to graphitic corrosion or other corrosion is detected, Turkey Point will assess the extent of the corrosion, and determine if inspection of other coolers and additional future monitoring are required.

Acceptance Criteria

If the inspection results in white non-porous metallic surface without major indications, Turkey Point may declare the part as "not affected by graphitic corrosion" and not require further evaluation. If there is evidence of significant effects of graphitic corrosion, an evaluation will be prepared to establish the minimum required wall thickness including a corrosion allowance adequate for a pre-determined inspection interval. Wall thickness measurements greater than minimum wall thickness values will be acceptable.

Confirmation Process

Follow-up examination requirements will be established based on the evaluation of the inspection results and will be entered into the corrective action program.

Operating Experience and Demonstration

Visual inspections and wall thickness measurements of equipment have been performed at Turkey Point for many years. The techniques have proven successful in determining actual material condition of components.

This Auxiliary Feedwater Pump Oil Coolers Inspection is a new program that will use techniques with demonstrated capability and a proven industry record to detect loss of material due to graphitic corrosion. Visual examination has been used in the past to identify graphitic corrosion. This inspection will be performed utilizing approved procedures and qualified personnel.

Based upon the above, the implementation of the Auxiliary Feedwater Pump Oil Coolers Inspection will provide reasonable assurance that loss of material will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with current licensing basis for the period of extended operation.

3.1.2 AUXILIARY FEEDWATER STEAM PIPING INSPECTION PROGRAM

As identified in Chapter 3, the Auxiliary Feedwater Steam Piping Inspection Program is credited for aging management of steam piping associated with Auxiliary Feedwater and Condensate Storage.

Scope

The Auxiliary Feedwater Steam Piping Inspection Program will manage the effects of loss of material due to general and pitting corrosion on the internal and external surfaces of the auxiliary feedwater steam supply carbon steel piping and fittings. The program will provide for representative volumetric examinations to detect loss of material in the auxiliary feedwater steam piping between the steam supply check valves and each of the three auxiliary feedwater pump turbines. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

No preventive actions are applicable to this program.

Parameters Monitored or Inspected

The program will monitor the wall thickness of representative piping/fittings in the auxiliary feedwater steam supply headers and the drain lines upstream of the steam traps. The volumetric examination will identify potential effects of inside diameter corrosion due to accumulation of water at the bottom of horizontal run pipes and outside diameter corrosion at areas of contact with the lower section of wet insulation.

Detection of Aging Effects

The aging effect of concern, loss of material due to general and pitting corrosion, will be evident by the reduced wall thickness in the piping/fittings.

Monitoring and Trending

The examination will initially be performed every five years. Piping/fittings thickness measurements will permit calculation of an integrated inside diameter and outside diameter corrosion rate. Inspection frequency may be adjusted based on corrosion rate to insure that the minimum wall thickness requirements will be maintained.

Acceptance Criteria

Wall thickness measurements greater than minimum values for the component design of record will be acceptable. Wall thickness measurements less than required minimum values will be entered into the corrective action program.

Confirmation Process

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

Operating Experience and Demonstration

Ultrasonic and computer aided radiography wall thickness measurement techniques have been performed at Turkey Point for years. These techniques have proven successful in determining wall thickness of piping and other components. Computer aided radiography has been used in the auxiliary feedwater steam supply headers and drain lines. The results of these examinations have detected some areas of localized corrosion in the headers.

This new program will use techniques with demonstrated capability and a proven industry record to measure pipe wall thickness. The examinations will be performed utilizing approved plant procedures and qualified personnel.

Based on the above, the implementation of the Auxiliary Feedwater Steam Piping Inspection Program will provide reasonable assurance that loss of material will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.1.3 EMERGENCY CONTAINMENT COOLERS INSPECTION

As identified in Chapter 3, the Emergency Containment Coolers Inspection is credited for aging management of cooler tubes in Emergency Containment Cooling.

Scope

The Emergency Containment Coolers Inspection is a one-time inspection that will determine the extent of loss of material due to erosion in the emergency containment cooler tubes of Units 3 and 4. A sample of tubes for examination will be selected based on piping geometry and flow conditions that represent those with the greatest susceptibility to erosion. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

No preventive actions are applicable to this inspection.

Parameters Monitored or Inspected

The inspection will document wall thickness of the emergency containment cooler heat exchanger tubes.

Detection of Aging Effects

The aging effect of concern, loss of material due to erosion, will be detected and sized in accordance with the volumetric technique chosen.

Monitoring and Trending

As stated above, this is a one-time inspection and as such no monitoring and trending is anticipated. The evaluation of the inspection results may result in additional testing, monitoring, and trending.

Acceptance Criteria

The results of the inspection will be evaluated by Turkey Point to verify that the minimum required wall thickness for the emergency containment cooler heat exchanger tubes will be maintained during the period of extended operation.

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 wall thickness (loss of material due to erosion). Effective and proven volumetric examination techniques will be selected for use in performing this inspection. This inspection will be performed utilizing approved procedures and qualified personnel.

Based upon the above, the implementation of the Emergency Containment Coolers Inspection will provide reasonable assurance that loss of material due to erosion will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.1.4 FIELD ERECTED TANKS INTERNAL INSPECTION

As discussed in Chapter 3, the Field Erected Tanks Internal Inspection is credited for aging management of field erected tanks in the following systems:

- Auxiliary Feedwater and Condensate Storage
- Feedwater and Blowdown
- Safety Injection

Scope

This is a one-time inspection of the two condensate storage tanks, two refueling water storage tanks, and the shared demineralized water storage tank. The Field Erected Tanks Internal Inspection is credited with managing the aging effect of loss of material due to corrosion of the tanks within the scope. The one-time inspection of selected internal areas, including surface welds, will determine the extent of internal corrosion in the listed tanks. The visual inspection will consist of direct (e.g., divers) or remote (e.g., television cameras, fiber optic scopes, periscopes) means. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

Internal tank surfaces are coated to reduce corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

The material condition of the internal surfaces of accessible areas of the tanks will be visually inspected.

Detection of Aging Effects

The presence of corrosion that could lead to loss of material will be determined by visual inspection of the accessible areas of the field erected tanks. Internal surfaces will be examined for evidence of flaking, blistering, peeling, discoloration, pitting, or excessive corrosion.

Monitoring and Trending

As noted above, this is a one-time inspection, therefore, monitoring or trending is not anticipated. Results of the inspection will be evaluated to determine if additional actions are required.

Acceptance Criteria

The results of the one-time inspection will be evaluated. Specific acceptance criteria will be provided in the implementing procedure.

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

Visual inspections have been performed at Turkey Point for several years. This technique has proven successful for identifying material defects on the surface of field erected tanks.

This inspection is a new activity that will use techniques with demonstrated capability and a proven industry record to detect corrosion. This inspection will be performed utilizing approved procedures and qualified personnel.

Based upon the above, the implementation of the Field Erected Tanks Internal Inspection will provide reasonable assurance that loss of material due to corrosion will be managed such that the structures and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.1.5 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 Storage

Chemical and Volume Control

Component Cooling Water

Containment Spray

Control Building Ventilation

Emergency Containment Cooling

Emergency Diesel Generators and Support Systems

Feedwater and Blowdown

Fire Protection

Instrument Air

Normal Containment and Control Rod Drive Mechanism Cooling

Reactor Coolant

Residual Heat Removal

Safety Injection

Spent Fuel Pool Cooling

Turbine Building Ventilation

Waste Disposal

Scope

The Galvanic Corrosion Susceptibility Inspection Program will manage the potential effects of loss of material due to galvanic corrosion on the internal surfaces of susceptible piping and components. Carbon steel components directly coupled to stainless steel components in raw water systems at Turkey Point are the most susceptible to galvanic corrosion. However, baseline examinations will be performed and evaluated to establish if the corrosion mechanism is active in other systems. The program will involve selected one-time inspections (see Monitoring and Trending below) whose results will be utilized to determine the need for additional actions. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

Components and systems utilize insulating flanges or cathodic protection to minimize galvanic corrosion. The use of insulated flanges and cathodic protection is not credited with the 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 represent the most limiting conditions. Selection of the most limiting conditions will be based on high galvanic potential, high cathode/anode area ratio, and high conductivity of the fluid in contact with the materials.

Detection of Aging Effects

Loss of material due to galvanic corrosion will be evident by material loss at the location of the junction between the dissimilar metals. Volumetric examinations or visual inspections will be utilized to address the extent of material loss.

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 (i.e., greatest galvanic potential, high cathode/anode area ratio, and high fluid conductivity). Initial inspection results will be utilized to assess the need for expanded sample locations. Inspection frequency will be determined based on the corrosion rate identified during the initial inspections.

Acceptance Criteria

Wall thickness measurements greater than required minimum wall thickness values for the components will be acceptable. Wall thickness measurements less than required minimum values will be entered into the corrective action program.

Confirmation Process

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

Operating Experience and Demonstration

Visual and volumetric inspection techniques have been used at Turkey Point for years. These techniques have proven successful in determining material condition of components.

This 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 procedures and qualified personnel. The inspection techniques used in this program have been previously used to monitor material condition for plant systems.

Based upon the above, the implementation of the Galvanic Corrosion Susceptibility Inspection Program will provide reasonable assurance that loss of material due to galvanic corrosion will be managed such that the systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.1.6 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.

The Reactor Vessel Internals Inspection Program will involve the combination of several activities culminating in the inspection of the Turkey Point Units 3 and 4 reactor vessel internals once for each unit during the 20-year period of extended operation, as described below. This 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 measurement of critical parts to evaluate potential dimensional changes. Accordingly, an evaluation will be performed to establish the requirements for dimensional verification of critical reactor vessel internals parts as part of the visual examination scope.

The Reactor Vessel Internals Inspection Program consists of two types of examinations, visual and ultrasonic testing. These examinations will manage the aging effects of cracking, reduction in fracture toughness, and loss of mechanical closure integrity. Commitment dates associated with the implementation of this new program are contained in Appendix A.

3.1.6.1 VISUAL EXAMINATION

Scope

This activity will manage the aging effects of cracking due to irradiation assisted stress corrosion (IASCC) and reduction in fracture toughness due to irradiation and thermal embrittlement on accessible parts of the Turkey Point Units 3 and 4 reactor vessel internals. The reactor vessel internals parts susceptible to these aging effects and included in the visual examination scope are accessible areas of the lower core plates and fuel pins, lower support columns, core barrels, baffle/former assemblies, thermal shields, and lower support castings. The program will consist of

VT-1 examinations utilizing remote equipment such as television cameras, fiberoptic scopes, periscopes, etc.

Preventive Actions

There are no practical preventive actions available that will prevent IASCC and reduction in fracture toughness. However, to minimize the potential for IASCC, the concentrations of chlorides, fluorides, and sulfates in the reactor coolant are controlled by implementation of the Chemistry Control Program.

Parameters Monitored or Inspected

This examination monitors the effects of cracking and reduction in fracture toughness on the reactor vessel internals selected parts by the detection and sizing of cracks.

Detection of Aging Effects

IASCC and reduction in fracture toughness of reactor vessel internals selected parts will be detected by performance of VT-1 examinations for the detection of cracks. Cracking is expected to initiate at the surface and, therefore, will be detectable by visual examination.

Monitoring and Trending

The VT-1 examination of selected parts of the reactor vessel internals will be performed one time for each unit during the period of extended operation. Based on the results of each examination, additional examinations and/or repairs will be scheduled.

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.

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 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. Similar visual examinations were successfully performed at St. Lucie Unit 1 during the core barrel repair/modification.

3.1.6.2 ULTRASONIC EXAMINATION

Scope

This activity manages the aging effect of loss of mechanical closure integrity on reactor vessel internals baffle/former bolts, barrel/former bolts, and lower support column bolts. The volumetric examination will involve ultrasonic testing on the baffle/former bolts in each unit to supplement the current examination techniques. The results of this examination will be utilized to determine the need for similar examinations of the barrel/former bolts, lower support column bolts, and other reactor vessel internals bolting.

Preventive Actions

There are no practical preventive actions available that will prevent loss of mechanical closure integrity of reactor vessel internals bolting. However, to minimize the potential for loss of mechanical closure integrity due to IASCC, the concentrations of chlorides, fluorides, and sulfates in the reactor coolant are controlled by implementation of the Chemistry Control Program.

Parameters Monitored or Inspected

This examination monitors loss of mechanical closure integrity of the reactor vessel internals bolts by the detection and sizing of cracks.

Detection of Aging Effects

The aging effect of loss of mechanical closure integrity of reactor vessel internals bolting will be detected by performance of ultrasonic examinations.

Monitoring and Trending

The ultrasonic examination of the reactor vessel internals baffle/former bolts will be performed one time during the period of extended operation. Based on the results of the examination, additional examinations and/or repairs will be scheduled.

Acceptance Criteria

The quantity of cracked baffle/former bolts shall be less than the number of bolts that can be damaged without affecting the intended function of the reactor vessel internals. This quantity will be established by evaluation.

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 ultrasonic examination methods are proven techniques that have been used in other programs to successfully detect cracking. Ultrasonic examinations have been demonstrated as an effective method of detecting cracking in baffle/former bolting at other Westinghouse plants.

The ultrasonic examinations utilize techniques with a demonstrated capability and a proven industry record to detect cracking. These examinations are performed utilizing approved procedures and qualified personnel.

Based upon the above, the implementation of the Reactor Vessel Internals Inspection Program will provide reasonable assurance that cracking, reduction in fracture toughness, and loss of mechanical closure integrity will be managed such that reactor vessel internals components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.1.7 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.

Scope

The Small Bore Class 1 Piping Inspection will be a one-time inspection of a sample of Class 1 piping less than 4 inches in diameter. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

No preventive actions are applicable to this inspection.

Parameters Monitored or Inspected

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

Detection of Aging Effects

The aging effect requiring management, cracking, will be detected and sized in accordance with the volumetric technique chosen.

Monitoring and Trending

As noted above, this is a one-time inspection and as such, no monitoring and trending is anticipated. The evaluation of the inspection results may result in additional examinations consistent with ASME Section XI, Subsection IWB. A small sample of the affected welds will be selected for examination based on piping geometry, piping size, and flow conditions.

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, which will use techniques with demonstrated capability and a proven industry record to detect piping weld and base material flaws. Effective and proven volumetric examination techniques will be selected for use in performing this inspection. This inspection will be performed utilizing approved procedures and qualified personnel. Results and recommendations from industry initiatives will be incorporated into the inspection.

Based upon the above, the Small Bore Class 1 Piping Inspection will provide reasonable assurance that cracking in small bore Class 1 piping welds will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2 EXISTING AGING MANAGEMENT PROGRAMS

3.2.1 ASME SECTION XI INSERVICE INSPECTION PROGRAMS

The ASME Section XI Inservice Inspection Programs within the scope of license renewal include the following:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program
- ASME Section XI, Subsection IWE Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- ASME Section XI, Subsection IWL Inservice Inspection Program

3.2.1.1 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 Reactor Coolant Systems.

A request to revise the Turkey Point Unit 3 inservice inspection scope for Class 1 piping to risk informed inservice inspection (RI-ISI) has been submitted to the NRC [Reference B-3]. The revision affects the nondestructive examination (NDE) scope of Class 1 piping currently required by ASME Section XI. Examinations performed are based upon the postulated failure mechanism associated with the piping being inspected. A similar revision request will be submitted for Turkey Point Unit 4 at a later date.

Scope

This program, as defined by the Third Interval Inservice Inspection Program for Turkey Point Nuclear Units 3 and 4 [Reference B-4], is credited with managing the aging effects of cracking, loss of mechanical closure integrity, and loss of material for piping and components. This program provides inspection and examination of accessible components, including welds, pump casings, valve bodies, steam generator tubing, and pressure-retaining bolting.

Inservice inspection requirements may be modified by applicable relief requests and code cases that are approved specifically for each unit. A particular code edition is applicable for a 120-month interval. Prior to the end of each interval, the program is revised to reflect the update requirements of 10 CFR 50.55a.

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.

Preventive Actions

There are no specific preventive actions under this program to prevent the effects of aging. Specific actions that serve to limit the effects of aging for Class 1, 2, and 3 piping and components are conservative design, fabrication, construction, inservice inspections, and strict control of chemistry.

Parameters Monitored or Inspected

Inservice examinations include visual inspections, surface examinations, and volumetric examinations in accordance with the requirements of ASME Section XI.

Detection of Aging Effects

The degradation of piping and components is determined by visual, surface, or volumetric examination in accordance with the requirements of ASME Section XI as modified by the Third Interval Inservice Inspection Program for Turkey Point Nuclear Units 3 and 4 [Reference B-4]. Piping and components are examined for evidence of operation-induced flaws using volumetric and surface techniques. The VT-1 visual examination is used to detect cracks, symptoms of wear, corrosion, erosion, or physical damage. VT-2 examinations are conducted to detect evidence of leakage from pressure-retaining components. VT-3 examinations are conducted to determine the general mechanical and structural condition of components and to detect discontinuities and imperfections such as loss of integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion. The extent and frequency of inspections is specified in ASME Section XI as modified in accordance with the Third Interval Inservice Inspection Program for Turkey Point Nuclear Units 3 and 4 [Reference B-4]. The frequency and scope of examinations are sufficient to ensure that the aging effects are detected prior to impacting the component intended functions. The inspection intervals are not restricted by the Code to the current term of operation and are valid for the period of extended operation.

Monitoring and Trending

The frequency and scope of examinations are sufficient to ensure that the aging effects are detected before impacting the component intended functions. Inspections are performed in accordance with the inspection intervals specified by ASME Section XI as modified by the Third Interval Inservice Inspection Program for Turkey Point Nuclear Units 3 and 4 [Reference B-4].

Examinations performed during any inspection interval that reveal flaws or areas of degradation exceeding the acceptance criteria are to be extended to include additional examinations within the same category. When examination results require evaluation of flaws or areas of degradation, the areas are reexamined during subsequent inspection intervals in accordance with the requirements of ASME Section XI.

Records of the inspection program, examination and test procedures, results of activities, examination/test data, and corrective actions taken or recommended are maintained in accordance with the requirements of ASME Section XI, Subsection IWA.

Acceptance Criteria

Acceptance standards for the inservice inspections are identified in ASME Section XI. Relevant indications that are revealed by the inservice inspections may require additional inspections of similar components in accordance with ASME Section XI. Examinations that reveal indications exceeding the acceptance standards are made acceptable by repair, replacement, or evaluation.

Confirmation Process

When areas of degradation are identified, an evaluation is performed to determine if repair or replacement is required. The results are documented in accordance with the corrective action program. Reexaminations are conducted for repaired flaws or areas of degradation to demonstrate that the repairs meet the acceptance standards.

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. Components are chosen for inspection in accordance with the requirements of Subsections IWB, IWC, and IWD and are inspected using the volumetric, surface, or visual examination methods.

The ASME Section XI inspections are conducted as part of the inservice inspections typically performed during plant refueling outages. The inservice inspection of Class 1, 2, and 3 components and piping has been conducted since initial plant start-up as required by the plant Technical Specifications and 10 CFR 50.55a. These inspections have documented, evaluated, and corrected degraded conditions associated with piping and components inspected under the program.

Implementation of the ASME Section XI program at Turkey Point currently includes over 480 Class 1, Class 2, and Class 3 examinations per unit per ten-year interval. For Class 1 piping, the examinations have yielded only indications of surface anomalies and surface geometry with no indication of fatigue cracking. For Class 2 piping, the only indications have been surface anomalies, acceptable slag inclusions, surface geometry, and fatigue cracking of steam generator feedwater nozzle reducers. The feedwater reducers were replaced and subsequent inspections are being performed in accordance with the requirements of ASME Section XI (see Section 3.2).

Based on the above, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provides reasonable assurance that the aging effects of cracking, loss of mechanical closure integrity, and loss of material will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the extended period of operation.

3.2.1.2 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.

Scope

The ASME Section XI, Subsection IWE Inservice Inspection Program is credited with managing the effects of loss of material for containment steel components and change in material properties for elastomers (seals, gaskets, and moisture barriers) associated with containment steel components. The program provides inspection and examination of accessible surface areas, including surfaces of welds, pressure-retaining bolting, and moisture barriers intended to prevent intrusion of moisture against inaccessible Containment metallic surfaces.

Preventive Actions

Visual inspections are performed to detect loss of material due to general corrosion and change in material properties of elastomers due to embrittlement and permanent set. Carbon steel surfaces are typically coated, in accordance with plant procedures, to reduce the effects of loss of material due to corrosion. In addition, cathodic protection and moisture barriers are used where appropriate to minimize corrosion. However, coatings, cathodic protection, and moisture barriers are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

The ASME Section XI, Subsection IWE Inservice Inspection Program provides for examination of the following categories as defined by ASME Section XI, Subsection IWE and the Turkey Point Inservice Inspection Program:

- Examination Category E-A, Containment Surfaces
- Examination Category E-C, Containment Surfaces Requiring Augmented Examination
- Examination Category E-D, Seals, Gaskets, and Moisture Barriers
- Examination Category E-G, Pressure-retaining Bolting
- Examination Category E-P, All Pressure-retaining Components

Surface conditions are monitored through visual examinations to determine the existence of corrosion. Surfaces that are inaccessible require an evaluation of the acceptability when conditions in accessible areas exist that could indicate the presence of or result in degradation to such inaccessible areas. Moisture barriers are visually inspected for degradation per Category E-D. Seals and gaskets are pressure tested in accordance with 10 CFR 50, Appendix J, per Category E-P.

Detection of Aging Effects

The presence of corrosion that could lead to loss of material is determined by visual inspection of the steel components. Surfaces are examined for evidence of flaking, blistering, peeling, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, or other signs of surface irregularities.

All pressure-retaining components, per Category E-P, require leakage testing in accordance with 10 CFR 50, Appendix J, to evaluate the change in material properties for airlocks, seals, and gaskets. Under the inspection plan, 100% of the accessible surfaces are inspected during the inspection intervals as established by the ASME Section XI, Subsection IWE, Inservice Inspection Program.

Monitoring and Trending

In accordance with the requirements of 10 CFR 50.55a, the first-period inspections for Turkey Point are scheduled for completion prior to September 9, 2001. Subsequent inspections are performed in accordance with the inspection intervals specified by ASME Section XI, Subsection IWE, and the ASME Section XI, Subsection IWE Inservice Inspection Program.

Surface areas likely to experience accelerated degradation and aging require augmented examinations and include areas as determined by the ASME Section XI, Subsection IWE Inservice Inspection Program. Identification of the areas subject to augmented examinations will be accomplished in accordance with the corrective action program and monitoring of industry events.

Examinations performed during any inspection interval that reveal flaws or areas of degradation exceeding the acceptance criteria are expanded to include additional examinations within the same category. When examination results require evaluation of flaws or areas of degradation, the area(s) are reexamined during the next inspection interval. Flaws or areas of degradation are documented and evaluated in accordance with the corrective action program and the requirements of the ASME Section XI, Subsection IWE Inservice Inspection Program.

Acceptance Criteria

Examinations and evaluations are performed under the direction of the Responsible Engineer in accordance with the requirements of ASME Section XI, Subsection IWE, and the ASME Section XI, Subsection IWE Inservice Inspection Program. Inspection results are evaluated against the acceptance standards of the program. Inspections that reveal evidence of degradation exceeding the acceptance standards may be subject to additional inspections to determine the nature and extent of the condition.

Confirmation Process

When areas of degradation are identified, an evaluation is performed to determine if repair or replacement is required. The results are documented in accordance with the corrective action program. Reexaminations are conducted for repaired flaws or areas of degradation to demonstrate that the repairs meet the acceptance standards.

Operating Experience and Demonstration

ASME Section XI, Subsection IWE was recently incorporated by reference in 10 CFR 50.55a and, accordingly, the Turkey Point program was developed. Full implementation is scheduled for September 2001. The current inspections of the containment liner are conducted in accordance with the Containment Leak Rate Testing Program and the Maintenance Rule Implementation Program. The inspections performed under these programs were previously documented and evaluated for any degraded conditions associated with the containment liner.

Containment leak-tight verification and visual examination of the steel components that are part of the leak-tight barrier have been conducted at Turkey Point since initial unit startup. Prior to the development of the ASME Section XI, Subsection IWE Inservice Inspection Program, examinations were performed in accordance with 10 CFR 50, Appendix J. Appendix J requires that licensees provide for preoperational and periodic verification, by performing tests of the leak-tight integrity of the Containment, and systems and components that penetrate the Containment.

Approved plant procedures provide the requirements, precautions/limitations, and acceptance criteria for the visual inspection of Unit 3 and Unit 4 accessible interior and exterior Containment surfaces, including the liner plate. Detailed inspections and evaluations are performed as warranted if gross discrepancies are detected. All conditions noted during the inspection of the Containment are documented on inspection reports. The inspection procedures provide general guidelines for inspection in accordance with NEI 94-01, "Industry Guidelines for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J" [Reference B-6].

Material properties for non-metallic components, such as gaskets and seals, change over time and are replaced in accordance with approved plant procedures. The Appendix J tests performed at the Turkey Point units during the years of operation have not shown any loss of intended function of the containment steel components that were attributed to loss of material or other aging effects.

The ASME Section XI, Subsection IWE Inservice Inspection Program incorporates the inspection criteria from the current inspection programs, which are similar to the Subsection IWE requirements.

FPL's Nuclear Quality Assurance Department performed an audit on the program and concluded that the Turkey Point ASME Section XI, Subsection IWE Inservice Inspection Program met the requirements of 10 CFR 50.55a and ASME Section XI, Subsection IWE, for inspection of Class CC metallic liners and pressure retention components.

The NRC Safety Evaluation Report for the Turkey Point Inservice Inspection Program [Reference B- 5] concluded there were no deviations from the regulatory requirements or commitments.

Based on the above, the continued examinations performed under the guidance of the ASME Section XI, Subsection IWE Inservice Inspection Program provide reasonable assurance that the aging effects loss of material and change of material properties for the containment steel components within the scope of license renewal will be managed for the period of extended operation.

3.2.1.3 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:

- Auxiliary Building
- Containments
- Emergency Diesel Generator Buildings
- Yard Structures

Scope

The ASME Section XI, Subsection IWF Inservice Inspection Program is credited with managing the aging effect of loss of material for Class 1, 2, and 3 component supports. The scope of the Turkey Point program provides inspection and examination of accessible surface areas of these component supports.

Preventive Actions

Carbon steel surfaces are typically coated, in accordance with plant procedures, to reduce the effects of loss of material due to corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

Class 1, 2, and 3 component supports are examined in accordance with ASME Section XI, Subsection IWF. The ASME Section XI, Subsection IWF Inservice Inspection Program provides for visual examination for general corrosion that could reduce the structural capacity of the component supports.

Detection of Aging Effects

The presence of corrosion that could lead to loss of material is determined by visual inspection of component supports. Surfaces are examined for evidence of flaking, blistering, peeling, discoloration, wear, pitting, corrosion, arc strikes, gouges, surface discontinuities, dents, or other signs of surface irregularities. The extent and frequency of the inspections is in accordance with ASME Section XI, Subsection IWF.

Monitoring and Trending

The selected supports are monitored each inspection period. The program inspects 25% of non-exempt Class 1 piping supports, 15% of Class 2 piping supports, and 10% of Class 3 piping supports, including exposed surfaces of structural bolting. For those component supports within a system that have similar design, function, and service, only one support is examined. Unacceptable supports are subject to corrective measures or evaluation, and are re-examined during the next inspection period.

Acceptance Criteria

Acceptance standards for the examination and evaluation of supports are provided in ASME Section XI, Subsection IWF. A condition observed during a visual examination that requires supplemental examination, corrective measures, repair, replacement, or analytical evaluation is categorized as a relevant condition and is not considered acceptable.

Confirmation Process

Component supports subject to corrective measures in accordance with ASME Section XI, Subsection IWF, are re-examined during the next inspection period and documented in accordance with the corrective action program. If additional corrective measures are not required, the examinations revert back to the original schedule of successive inspection intervals.

Operating Experience and Demonstration

The ASME Section XI, Subsection IWF, inspections are conducted as part of the inservice inspections typically during plant refueling outages. The inspection of Class 1, 2, and 3 component supports has been conducted since initial plant startup as required by Technical Specifications.

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). These supports are chosen for inspection in accordance with the requirements of ASME Section XI, Subsection IWF, and shall be inspected using visual examination methods.

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. All conditions noted during the inspection of component supports, whether or not they are considered to require further review, are documented on inspection reports.

The NRC Safety Evaluation Report for the Turkey Point Inservice Inspection Program [Reference B-5] concluded that there were no deviations from regulatory requirements or commitments. The FPL Nuclear Division Quality Assurance Department performed an audit of the Inservice Inspection Program. This audit concluded that the program was complete and in compliance with the requirements of the ASME Code, Section XI, and applicable commitments.

Based on the above, the continued examinations performed under the ASME Section XI, Subsection IWF Inservice Inspection Program provide reasonable assurance that the aging effect loss of material for the Class 1, 2, and 3 components and piping supports within the scope of license renewal will be managed for the period of extended operation.

3.2.1.4 ASME SECTION XI, SUBSECTION IWL INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the ASME Section XI, Subsection IWL Inservice Inspection Program is credited for aging management of the post-tensioning system structural components in the Containments.

Scope

The ASME Section XI, Subsection IWL Inservice Inspection Program is credited for managing the aging effect of loss of material for the containment post-tensioning system structural components. The scope of the program provides for inspection of tendon wires and tendon anchorage hardware surfaces for loss of material, as well as a confirmatory program for measurement of tendons for loss of prestress.

Preventive Actions

A layer of non-structural low strength concrete protects the top filler caps of the containment vertical tendons. This layer of concrete prevents the intrusion of rainwater under the caps and any subsequent corrosion of the tendon assemblies. This concrete also prevents the accumulation of rainwater behind the ring girder. Additionally, metal caps are installed over tendon anchorages.

Additionally, all the metallic components (such as reinforcing bars, liner plate, and tendon anchorages) are interconnected to an impressed current cathodic protection system to prevent galvanic corrosion. The cathodic protection system is a non-safety related system that supports the protection of the steel components from corrosion. However, this protective system is not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

In accordance with ASME Section XI, Subsection IWL, unbonded post-tensioning system components are examined. These components consist of tendons, wires or strand, anchorage hardware and surrounding concrete, corrosion protection medium, and free water. Surface conditions are monitored through visual examinations to determine the extent of corrosion or concrete degradation around anchorage locations. Prestress forces are measured for sample tendons to determine loss of prestressing force. Tension tests are performed on removed wire or strand samples to examine for corrosion and mechanical damage.

Detection of Aging Effects

The presence of age-related degradation is determined by visual inspection or by measurement. Tendon anchorage hardware is examined for corrosion. A select number of tendons are completely detensioned and a sample wire from each group of tendons is examined for the presence of corrosion and tested to verify ultimate strength. Tendon anchorage hardware and concrete surfaces are examined for corrosion protection medium leakage and the tendon caps are examined for deformation.

Monitoring and Trending

In accordance with 10 CFR 50.55a, the first-period inspections for Turkey Point are scheduled for completion by September 9, 2001. Subsequent tendon inspections are performed in accordance with the inspection intervals specified by ASME Section XI, Subsection IWL.

Tendons examined are selected on a random basis among the tendons that have not been examined during previous inspections. A sample of each tendon types, in accordance with ASME Section XI, Subsection IWL, is examined during each inspection interval. Reduced sample size may be used if the applicable criteria of ASME Section XI, Subsection IWL, are met during each of the earlier inspections.

The tendons inspected under the ASME Section XI, Subsection IWL Inservice Inspection Program provide results to evaluate for loss of material and loss of prestress. These previous tendon surveillance records are maintained and the results documented for future use. Prestress limits are calculated and tabulated for each group of tendons examined. All surveillance results are reviewed in order to ensure that any recommendations are considered for incorporation into the surveillance program.

Acceptance Criteria

Examinations and evaluations are performed under the direction of the Responsible Engineer in accordance with the requirements of ASME Section XI, Subsection IWL, and the ASME Section XI, Subsection IWL Inservice Inspection Program. The Responsible Engineer evaluates the inspection results and determines whether analysis, repair, or additional inspections or testing are required. Inspection results are evaluated against the acceptance standards in accordance with ASME Section XI, Subsection IWL, and the ASME Section XI, Subsection IWL Inservice Inspection Program.

Confirmation Process

When areas of degradation are identified, an evaluation is performed to determine if repair or replacement is required. The results are documented in accordance with the corrective action program. Following repair or replacement activities, a containment pressure test would be conducted, if required, in accordance with the ASME Section XI, Subsection IWL Inservice Inspection Program, to confirm the adequacy of the corrective action. In addition, repaired areas are reexamined.

Operating Experience and Demonstration

ASME Section XI, Subsection IWL, was recently adopted by 10 CFR 50.55a and, accordingly, the Turkey Point program was developed. Implementation is scheduled prior to September 2001. Previous inspections of the tendons and tendon anchorages were conducted in accordance with Technical Specifications, the UFSAR, and plant procedures. The inspections performed under these programs were documented and evaluated any degraded conditions associated with the post-tensioning system. The ASME Section XI, Subsection IWL Inservice Inspection Program incorporates the inspection criteria from the current post-tensioning system inspection programs, which are similar to Subsection IWL.

The containment tendon examination program has been conducted since initial unit startups at 5-year intervals. The containment tendon surveillance examination requirements incorporated the general criteria and requirements of Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments" [Reference B-7].

This tendon surveillance program included provisions for determining that a tendon retains a lift-off force equal to or greater than its predicted lower limit. The surveillance program requires visual inspections to detect the presence of water; examination of all anchorage components for indications of corrosion, pitting, cracking, distortion, or damage; examination of surrounding concrete; and examination of removed tendon wire for signs of gross corrosion or damage.

An example of the overall effectiveness of the tendon inspection program is supported by the results of the Turkey Point 20th year tendon surveillance. The measured lift-off forces for a number of randomly selected surveillance tendons were below the predicted lower limit. Condition Reports and a Licensee Event Report were issued. In accordance with the Technical Specifications, engineering evaluations were prepared and concluded that the lower than expected tendon lift-off forces were caused by greater than expected tendon wire relaxation losses due to average tendon temperatures higher than originally considered. To accommodate the increased prestress losses, a license amendment was submitted and approved to reduce the Containment design pressure from 59 psig to 55 psig, and a Containment re-analysis was performed to determine the new minimum required prestress forces to maintain Turkey Point licensing basis requirements. The results of the re-analysis are provided in the UFSAR, Section 5.1.3.

The ASME Section XI, Subsection IWL Inservice Inspection Program incorporates all of the inspection criteria and guidelines of the previous tendon inspection program attributes and is implemented using existing plant procedures.

Based upon the above, the continued implementation of the tendon inspections under the ASME Section XI, Subsection IWL Inservice Inspection Program provides reasonable assurance that the aging effects (loss of material and loss of prestress) will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.2 BORAFLEX SURVEILLANCE PROGRAM

As identified in Chapter 3, the Boraflex Surveillance Program is credited for aging management of the spent fuel racks associated with Spent Fuel Storage and Handling.

Scope

The Boraflex Surveillance Program is credited with managing the aging effect of change in material properties for the Boraflex material in the spent fuel storage racks for Units 3 and 4.

The program will be enhanced to provide for density testing (or other approved testing method) of the encapsulated Boraflex material in the spent fuel storage racks. Commitment dates associated with the enhancement of this program are contained in Appendix A.

Preventive Actions

Turkey Point is not aware of any preventive actions that can be taken to mitigate loss of boron carbide and silica release since the polymer matrix tends to break down over time due to the convective aqueous environment of the spent fuel pool. Continued monitoring of the Boraflex will assure that the 5% subcriticality margin will be maintained.

Parameters Monitored or Inspected

The Boraflex Surveillance Program seeks to determine the amount of degradation of the Boraflex material. The current program, consisting of blackness testing, confirms the in-service Boraflex panel performance data in terms of gap formation, gap distribution, and gap size. In addition, tracking of the spent fuel pool silica levels provides a qualitative indication of boron carbide loss from the panels. The enhanced Boraflex Surveillance Program will include checking the density (or other approved methods) of the Boraflex to ascertain the physical loss of boron carbide.

Detection of Aging Effects

The presence of silica, which is periodically monitored, in the spent fuel pool water is a physical sign of the aging effect occurring in the Boraflex material. The enhanced

Boraflex Surveillance Program will determine the amount of degradation of the Boraflex material.

Monitoring and Trending

Shrinkage, gaps, and density will be monitored during scheduled Boraflex surveillance testing. Subsequent Boraflex tests will be scheduled following evaluation of the measured results. Trends will be established following implementation of the enhanced Boraflex Surveillance Program.

Acceptance Criteria

Acceptance standards for Boraflex degradation are controlled by the assumptions in the criticality analysis. The results of each surveillance are used to evaluate the impact on the assumptions in the criticality analysis to assure that the 5% subcriticality margin will be maintained.

Confirmation Process

When areas of degradation are identified, an evaluation is performed to determine if corrective action is required. Subsequent testing will ensure the effectiveness of any corrective actions.

Operating Experience and Demonstration

The current Boraflex Surveillance Program was initiated following installation of high density spent fuel storage racks at Turkey Point. It is known that degradation of the Boraflex is occurring, as evidenced by silica accumulation in the spent fuel pool water.

Boraflex neutron attenuation (blackness) testing has been performed on a test frequency of once every five years on specific Boraflex panels in either Unit 3 or Unit 4 spent fuel pools. Evaluations of the test results have demonstrated that the required Technical Specification subcritical margin for storage of fuel in the spent fuel pools has been met. Turkey Point's response to NRC Generic Letter 96-04 [Reference B-9] assessed the capability of the Boraflex to maintain the five percent subcriticality margin and provided remedies for long-term Boraflex degradation.

Based upon the above, the continued implementation of the Boraflex Surveillance Program provides reasonable assurance that the effects of aging will be adequately managed such that the components within the scope of license renewal will perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.3 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 in the following systems and structures:

SYSTEMS

Auxiliary Building Ventilation

Chemical and Volume Control

Component Cooling Water

Containment Isolation

Containment Post Accident Monitoring and Control

Containment Spray

Electrical/ I&C Components

Emergency Containment Cooling

Emergency Containment Filtration

Feedwater and Blowdown

Fire Protection

Instrument Air

Intake Cooling Water

Main Steam and Turbine Generators

Normal Containment and Control Rod Drive Mechanism Cooling

Primary Water Makeup

Reactor Coolant

Residual Heat Removal

Safety Injection

Sample

Spent Fuel Pool Cooling

Waste Disposal

STRUCTURES

Auxiliary Building

Containments

Spent Fuel Storage and Handling

Yard Structures

Scope

The Boric Acid Wastage Surveillance Program manages the effects of loss of material and loss of mechanical closure integrity due to aggressive chemical attack of cast iron, carbon steel, and low alloy steel components and structural components including bolting. The program encompasses mechanical closures (e.g., bolted connections, valve packing, pump seals) in the above systems and structures and components containing, or exposed to, borated water. The 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 structural integrity of components, supports, or structures. This program includes electrical structural components (enclosures, cable trays, conduit, etc.) in proximity to borated water systems.

Some systems outside Containment (i.e., Spent Fuel Pool Cooling and portions of Waste Disposal associated with containment integrity) are currently inspected under other existing programs. The scope of the Boric Acid Wastage Surveillance Program will be enhanced to include these systems and components. Commitment dates associated with the enhancement of this program are contained in Appendix A.

Preventive Actions

The removal of concentrated boric acid and boric acid residue and the elimination of boric acid leakage mitigates corrosion by minimizing the exposure of the susceptible material to the corrosive environment.

Parameters Monitored or Inspected

Boric acid residue and borated water leakage are directly related to the degradation of components. The program monitors the effects of boric acid corrosion on the intended function of the component by detection of coolant leakage as required by NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR Plants" [Reference B-8], including guidelines for locating small leaks, conducting examinations, and performing evaluations.

Detection of Aging Effects

Degradation of the component due to boric acid corrosion cannot occur without leakage of coolant containing boric acid. Conditions leading to boric acid corrosion, such as crystal buildup, and evidence of moisture are readily detectable by visual inspections. Visual inspections are performed on external surfaces in accordance with plant procedures.

Monitoring and Trending

Leakage calculations are performed each shift. Visual inspection of systems inside Containment is conducted if unidentified leakage rates exceed 0.5 gpm. During each refueling, inspections of systems inside Containment are performed. Every 18 months inspections of borated water systems outside Containment are performed.

Acceptance Criteria

All identified cases of boric acid leakage are either corrected or evaluated.

Confirmation Process

Follow-up testing is performed to confirm satisfactory completion of corrective actions. For system leakage, this includes a visual inspection of the repaired components.

Operating Experience and Demonstration

The Boric Acid Wastage Surveillance Program was originally implemented as a result of boric acid leaks experienced at Turkey Point and NRC Generic Letter 88-05. This program addresses the Generic Letter requirements, including: 1) detection 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 wastage. It has provided for timely identification of leakage and implementation of corrective actions. Since establishing the program, there have been no instances of boric acid corrosion that have impacted license renewal system intended functions.

Based upon the above, the continued implementation of the Boric Acid Wastage Surveillance Program provides reasonable assurance that the aging effects (loss of material and loss of mechanical closure integrity) will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.4 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 Storage

Chemical and Volume Control

Component Cooling Water

Containment Post Accident Monitoring and Control

Containment Spray

Control Building Ventilation

Emergency Containment Cooling

Emergency Containment Filtration

Feedwater and Blowdown

Emergency Diesel Generators and Support Systems

Main Steam and Turbine Generators

Normal Containment and Control Rod Drive Mechanism Cooling

Primary Water Makeup

Reactor Coolant

Residual Heat Removal

Safety Injection

Sample

Spent Fuel Pool Cooling

Turbine Building Ventilation

Waste Disposal

STRUCTURES

Spent Fuel Storage and Handling (structural components exposed to fluid)

Scope

The Chemistry Control Program is credited for managing the aging effects of loss of material, cracking, and fouling buildup for the internal surfaces of primary and secondary systems and structures. The program includes sampling activities and analysis for treated water - primary, treated water - borated, treated water - secondary, treated water, and fuel oil.

Preventive Actions

No preventive actions are applicable to this program.

Parameters Monitored or Inspected

The parameters monitored by the Chemistry Control Program for the purposes of aging management are chloride, fluoride, sulfate, oxygen, biocide, corrosion inhibitor, and water content.

Detection of Aging Effects

The aging effects of concern (i.e., loss of material, cracking, and fouling) are minimized or prevented by controlling the chemical species that cause the underlying aging mechanisms that result in the aging effects. Alternatively, chemical agents, such as corrosion inhibitors and biocides, are introduced to prevent certain aging mechanisms. The chemistry parameters are measured utilizing standard proven industry techniques. The aging mechanisms that can be minimized or prevented by the Chemistry Control Program include general corrosion, pitting corrosion, crevice corrosion, microbiologically influenced corrosion, graphitic corrosion, stress corrosion cracking, intergranular attack, corrosion fouling, and fouling caused by microbiologically influenced corrosion.

Monitoring and Trending

Monitoring and trending requirements for all parameters controlled by the Chemistry Control Program are included in appropriate plant procedures.

Acceptance Criteria

The acceptance criteria for the chemistry parameters required to be monitored and controlled are in accordance with the Nuclear Chemistry Parameters Manual, Technical Specifications, and appropriate plant procedures.

Confirmation Process

Follow-up testing is performed to confirm satisfactory completion of corrective action.

Operating Experience and Demonstration

The Chemistry Control Program is an ongoing program at Turkey Point that considers the best practices of industry organizations, vendors, utilities, and water treatment experts. The program provides assurance that the fluid environments 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. The chemistry analyses are governed by the plant Quality Control Program to assure accurate results. Chemistry data are monitored for trends that might be indicative of an underlying operational problem.

The overall effectiveness of the program is supported by the excellent operating experience for systems, structures, and components that are influenced by the program. No chemistry-related degradation has resulted in loss of component intended functions on any systems for which the fluid chemistry is actively controlled. A review of plant condition reports indicates that Turkey Point Units 3 and 4 have not experienced any Level 3 excursions as defined by the Electric Power Research Institute's water chemistry guidelines. The program has been subject to periodic internal and external assessment activities that help to maintain highly effective chemistry control, and facilitate continuous improvement.

Based on the above, the continued implementation of the Chemistry Control Program provides reasonable assurance that the aging effects (loss of material, cracking, and fouling) will be managed such that components and systems within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.5 CONTAINMENT SPRAY SYSTEM PIPING INSPECTION PROGRAM

As identified in Chapter 3, the Containment Spray System Piping Inspection Program is credited for aging management of selected piping and fittings in Containment Spray.

Scope

This Containment Spray System Piping Inspection Program manages the aging effect of loss of material due to general, crevice, and pitting corrosion on the internal surfaces of carbon steel piping/fittings and valves wetted by boric acid in the containment spray headers.

Preventive Actions

Surveillance procedures require the closure of a second isolation valve in the containment spray headers when the pumps are started for testing.

Parameters Monitored or Inspected

The program monitors the wall thickness of selected piping/fittings in the spray headers within the Containments.

Detection of Aging Effects

Ultrasonic thickness measurement is utilized for this examination. The aging effect of concern, loss of material, is evident by the reduced wall thickness in the piping/fittings being examined.

Monitoring and Trending

The examination initially is performed each refueling outage. The piping/fittings thickness measurements permit calculation of a corrosion rate. Inspection frequency may be adjusted based on corrosion rate to insure that minimum wall thickness requirements for the pipe are maintained. If evaluation of the inspection results indicates that loss of material due to corrosion is not occurring, the Containment Spray System Piping Inspection Program may be discontinued.

Acceptance Criteria

Wall thickness measurements greater than minimum wall thickness values for the component design of record are acceptable. Wall thickness measurements less than the minimum required values are entered into the corrective action program.

Confirmation Process

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

Operating Experience and Demonstration

Ultrasonic thickness measurements have been performed for several years. The technique has proven successful at determining the wall thickness of piping/fittings and other components.

This is an existing program at Turkey Point that uses a technique with demonstrated capability and a proven industry record to measure wall thickness. This examination is performed utilizing approved procedures and qualified personnel. The ultrasonic thickness measurement technique has been previously used to measure the wall thickness in the containment spray system spray headers and other plant systems. The results of these examinations have detected some areas of localized corrosion in the headers, and the results are documented.

Based on the above, the continued implementation of the Containment Spray System Piping Inspection Program provides reasonable assurance that loss of material will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis 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, 3.7, and 4.4 of this Application).

Scope

The program includes the environmentally qualified devices that are within the scope of 10 CFR 50.49.

Preventive Actions

The program includes preventive actions required to maintain the qualification time period for the environmentally qualified devices.

Parameters Monitored or Inspected

The program establishes an aging limit (qualified life) for each installed device. The installed life of each device is monitored and appropriate actions (replacement, refurbishment, or requalification) are taken before the aging limit is exceeded.

Detection of Aging Effects

The program does not require the detection of aging effects for equipment while in service since effects are maintained within established acceptable limits by the Environmental Qualification Program actions. When the qualified life is less than the plant license period, the program requires replacement, refurbishment, or requalification of the component prior to the end of its qualified life. When unexpected adverse effects are identified during operational or maintenance activities, they are evaluated to determine the root cause and significance in accordance with approved procedures.

Monitoring and Trending

The installed life of each environmentally qualified device is monitored and appropriate actions (replacement, refurbishment, or requalification) are taken before the aging limit is exceeded. The program does not require monitoring or trending of condition or performance parameters of equipment while in service to manage the effects of aging.

Acceptance Criteria

The program requires replacement, refurbishment, or requalification prior to exceeding the life limit (qualified life) of each installed device.

Confirmation Process

Administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B, that will insure adequacy of corrective actions.

Operating Experience and Demonstration

The Environmental Qualification Program is an ongoing program at Turkey Point 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, radiation) at established frequencies with well-defined acceptance criteria. The Environmental Qualification Program is governed by the Quality Control Program to assure accurate results.

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. No environmental qualification related degradation has resulted in loss of component intended functions on any systems. The program has been subject to periodic internal and external assessment activities that help to maintain highly effective control and facilitate continuous improvement.

Based on the above, the Environmental Qualification Program is an effective program for managing the effects of aging to ensure that the components within the scope of license renewal will continue to perform their intended function consistent with the current licensing basis 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 Systems.

Scope

The Fatigue Monitoring Program tracks design cycles to ensure that Units 3 and 4 Reactor Coolant System components remain within their design fatigue limits. The specific fatigue analyses validated by this monitoring program include those for the reactor vessels, reactor vessel internals, pressurizers, steam generators, reactor coolant pumps, and pressurizer surge lines.

Preventive Actions

The program utilizes the systematic counting of design cycles to ensure that component design fatigue usage limits are not reached.

Parameters Monitored or Inspected

The parameters monitored by the program for confirmation purposes are the design cycles consistent with the Reactor Coolant System Class 1 component design analyses.

Detection of Aging Effects

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

Monitoring and Trending

Administrative procedures provide the methodology for logging design cycles. Guidance is provided as design cycle limits are approached.

Acceptance Criteria

The maximum allowable design cycles are specified in the plant administrative procedures and are listed in Chapter 4 of the UFSAR Supplement provided in Appendix A of this Application.

Confirmation Process

In order to stay within fatigue design limits, plant procedures require administrative action 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 Turkey Point since initial unit startups and has evolved over many years of plant operation. As demonstrated in Subsection 4.3.1 of this Application, the number of design cycles considered in the current licensing basis fatigue analyses is sufficiently conservative to account for not only the current licensing basis term, but the extended period of operation as well. Confirmation will be accomplished by continuation of the Fatigue Monitoring Program.

The FPL Quality Assurance Department performed a surveillance/audit of this program to assess the implementation of activities associated with maintaining the Reactor Coolant System plant components within design cycle limits. This audit identified no deficiencies.

In addition, an independent assessment of the Fatigue Monitoring Program concluded the administrative procedure accurately identifies and classifies plant design cycles, and provides an effective and consistent method for categorizing, counting, and tracking design cycles. The assessment concluded that the program maintains in-depth information for each design cycle counted. The assessment also concluded that design cycle severity bounds actual plant operation.

Based upon the above, the continued implementation of the Fatigue Monitoring Program provides reasonable assurance that Reactor Coolant Systems components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis 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 associated with Fire Protection and Fire Rated Assemblies.

Scope

The Fire Protection Program manages the aging effects of loss of material, cracking, and fouling for the components/piping of the Fire Protection System and Fire Rated Assemblies. Additionally, this program manages the aging effects of loss of material, loss of seal, cracking, and erosion for structures and structural components associated with fire protection.

The scope of the Fire Protection Program will be enhanced to include inspection of additional components. Commitment dates associated with the enhancement of this program are contained in Appendix A.

Preventive Actions

Many fire protection components are provided with a protective coating to minimize the potential for external corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

Surface conditions are monitored visually to determine the extent of external material degradation. Visual examination will detect loss of material due to general, crevice, and pitting corrosion; and loss of seal or cracking due to embrittlement. Internal conditions are monitored via leakage, flow, and pressure testing. Internal loss of material (due to general, crevice, and pitting corrosion; microbiologically influenced corrosion; and selective leaching) and blockage due to fouling 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 degradation on external surfaces is determined by visual examination. Surfaces of components and structures are examined for damage, deterioration, leakage, or other forms of corrosion.

Functional testing and flushing of the systems clears away internal scale, debris and other foreign material that could lead to blockage/obstruction of the system. Flow and pressure tests verify system integrity. Visual examinations of breached portions of the system also verify unobstructed flow and integrity of the piping/components.

Monitoring and Trending

The degradation found as a result of inspection/testing of the systems/components is addressed by the Fire Protection Program procedures. The evaluation of the inspection/testing results may result in additional testing, monitoring, and trending.

Acceptance Criteria

The results of the inspection/testing will be evaluated in accordance with the acceptance criteria in the appropriate fire protection procedure(s). Parameters required to be monitored and controlled are listed in the applicable documents.

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 returning the equipment to service.

Operating Experience and Demonstration

The Fire Protection Program has been an ongoing program at Turkey Point. The 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 National Fire Protection Association (NFPA) and Nuclear Electric Insurance Limited (NEIL) and is approved by the NRC.

The overall effectiveness of the program is demonstrated by the excellent operating experience of systems, structures, and components that are included in the Fire Protection Program. The program has been subjected 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 control.

Based upon the above, the continued implementation of the Fire Protection Program provides reasonable assurance that the aging effects (loss of seal, loss of material, cracking, and fouling) will be managed such that components/commodity groups within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis 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 piping and fittings in the following systems:

- Feedwater and Blowdown
- Main Steam and Turbine Generators

Scope

The Flow Accelerated Corrosion Program manages the aging effect of loss of material due to flow accelerated corrosion. The program predicts, detects, monitors, and mitigates flow accelerated corrosion wear in high energy carbon steel piping associated with Main Steam and Turbine Generators and Feedwater and Blowdown. The program includes analysis and limited baseline inspection, determination of the extent of thinning, repair/replacement as appropriate, and performance of follow-up inspections.

This program will be enhanced to address internal and external loss of material of steam trap lines due to flow accelerated corrosion and general corrosion, respectively. Commitment dates associated with the enhancement of this program are contained in Appendix A.

Preventive Actions

The rate of flow accelerated corrosion is affected by piping material, geometry and hydrodynamic conditions, and operating conditions, such as temperature, pH, steam quality, operating hours, and dissolved oxygen content. The susceptibility to flow accelerated corrosion is reduced by maintaining high water quality.

Parameters Monitored or Inspected

The program monitors the effects of flow accelerated corrosion in piping by measuring wall thickness using nondestructive examination, and by performing analytical evaluations. The inspection program stipulates visual, ultrasonic, or radiographic testing of susceptible locations based on operating conditions. For each location outside the acceptance guidelines, the inspection sample is expanded based on approved guidelines and engineering judgment. Analytical models are used to predict flow accelerated corrosion in piping systems based on specific plant data, including material and hydrodynamic and operating conditions. External piping wall loss of steam trap lines due to general corrosion will also be maintained by this program. Based on this, volumetric NDE techniques will be used on these lines.

Detection of Aging Effects

Aging degradation of piping and fittings occurs by wall thinning. The methods of inspections are visual, ultrasonic, and computer aided radiography. The extent and schedules of inspections ensure detection of wall thinning before the loss of intended function of this piping.

Monitoring and Trending

Inspections and analytical evaluations monitor and trend wall thinning. The inspection schedule is determined based on the remaining service life that is recalculated after each inspection. If degradation is detected such that the wall thickness is less than the minimum allowed wall thickness, additional examinations are performed in adjacent areas to bound the thinning.

External piping wall loss of steam trap lines due to general corrosion will also be monitored by this program based on the volumetric nondestructive examination techniques utilized for these lines. Inspection frequency for external corrosion monitoring will be developed based on the initial inspection results.

Acceptance Criteria

Inspection results are used to calculate the number of refueling or operating cycles remaining before the component reaches its minimum allowable wall thickness. If calculations indicate that an area will reach its minimum allowable wall thickness before the next inspection interval, the component is repaired, replaced, or reevaluated.

Confirmation Process

Follow-up inspections are scheduled based on the remaining service life that is recalculated after each inspection. Additionally, post maintenance testing is conducted after repairs.

Operating Experience and Demonstration

Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems, two-phase piping in extraction steam lines, and moisture separation reheater and feedwater heater drains, as identified in NRC generic communications. The Flow Accelerated Corrosion Program was originally implemented in response to NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" [Reference B-10]. The conservative philosophy established within the program has been successful in managing the loss of material due to erosion/corrosion. Various sections of the Main Steam and Turbine Generators and Feedwater and Blowdown piping are periodically examined using nondestructive examination 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 plant/industry experience warrants.

Ultrasonic examinations have identified piping wall thickness below the established screening criteria. These degradations were documented in accordance with the corrective action program and resulted in repair, replacement, or subsequent inspection of the piping.

This program has been reviewed by the NRC during several inspections with no deviations or violations identified. FPL Quality Assurance surveillances and reviews have been performed of the program with no deficiencies identified.

Based on the above, the continued implementation of the Flow Accelerated Corrosion Program provides reasonable assurance that the aging effects of flow accelerated corrosion will be managed such that Main Steam and Turbine Generators and Feedwater and Blowdown components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.10 INTAKE COOLING WATER SYSTEM INSPECTION PROGRAM

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

- Component Cooling Water
- Intake Cooling Water

Scope

NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment" [Reference B-11], recommended the implementation of an on-going program of surveillance and control techniques to significantly reduce flow blockage caused by biofouling, corrosion, erosion, protective coating failures, stress corrosion cracking, and silting problems in systems and components supplied by the Intake Cooling Water System. The Intake Cooling Water System Inspection Program was developed in response to this generic letter and addresses the aging effects of loss of material due to various corrosion mechanisms, stress corrosion cracking, and fouling due to macro-organisms for those components subject to raw water (i.e., salt water) conditions. The program utilizes performance testing and evaluations, systematic inspections, leakage evaluations, and corrective actions to ensure that loss of material, cracking, or biological fouling does not lead to loss of component intended functions.

This program will be enhanced to improve documentation of scope and frequency of the intake cooling water piping crawl-through inspections and component cooling water heat exchanger tube integrity inspections. Commitment dates associated with the enhancement of this program are contained in Appendix A.

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 protecting the intake cooling water piping and components, and also employs component cooling water heat exchanger performance monitoring, testing, and periodic tube inspections. Maintenance of the internal piping/component linings minimizes the potential loss of material due to corrosion that could impact the pressure boundary intended function. Performance monitoring and testing; channel head, tube sheet, and anode inspections; and tube examinations of component cooling water heat exchangers provide for early identification of internal fouling and tube degradation that can impact heat transfer and pressure boundary intended functions. External coatings are applied to portions of the Intake Cooling Water System to minimize corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

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

Performance monitoring, testing, and tube inspections of component cooling water heat exchangers - Pressures, temperatures, and flows are measured as part of periodic performance testing of the component cooling water heat exchangers to verify heat transfer capability. This testing is supplemented by routine monitoring of differential temperatures across the heat exchanger during operation. Tube integrity of the component cooling water heat exchangers is monitored by periodic nondestructive examination (e.g., eddy current testing) to ensure early detection of aging effects.

Detection of Aging Effects

Internal Piping/Component Inspections – Visual examination of the piping/ components and their internal linings is performed. Additional nondestructive testing may be utilized to measure surface condition and the extent of wall thinning based on the evaluation of the examination results and as documented in accordance with the corrective action program.

Performance monitoring, testing, and tube inspections of component cooling water heat exchangers – Periodic performance testing and monitoring are conducted to provide for early identification of fouling or 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

Internal Piping/Component Inspections – Inspections and frequencies are in accordance with commitments under Generic Letter 89-13. Internal piping/component inspections are performed periodically during refueling outages. Inspection frequencies are adjusted based upon experience and assure the timely detection of aging effects.

Performance monitoring, testing, and tube inspections of component cooling water heat exchangers – Online monitoring of system parameters is used to provide an indication of flow blockage. Heat transfer testing results are documented and reviewed in plant procedures. The heat transfer capability is trended to ensure that the component cooling water heat exchangers satisfy safety analysis requirements. component cooling water heat exchanger tube condition is determined by eddy current testing and documented accordingly. Heat exchanger tube cleanings, tube replacements, or other corrective actions are implemented as required.

This program will be enhanced to improve documentation of scope and frequency of the intake cooling water piping crawl-through inspections and component cooling water heat exchanger tube integrity inspections.

Acceptance Criteria

Internal Piping/Component Inspections – Biological fouling is considered undesirable and is removed or reduced during the inspection process. When required by procedure, wall thickness values are determined and evaluated.

Performance monitoring, testing, and tube inspections of component cooling water heat exchangers – Acceptance criteria are provided to ensure that the design basis heat transfer capability is maintained and to direct when component cooling water heat exchanger cleaning and inspection are required. Differential pressure criteria guidelines are provided to ensure that the intake cooling water design basis flow rate is maintained and to identify when backflushing or cleaning of the intake cooling water basket strainers is required.

Confirmation Process

Follow-up monitoring is performed to confirm satisfactory completion of corrective actions. This monitoring activity is verified as part of the system surveillances for determining minimum Intake Cooling Water System flows for cleaning basket strainers and for evaluating component cooling water heat exchanger performance, or following piping/tube inspections.

Operating Experience and Demonstration

The existing Intake Cooling Water System Inspection Program has been an ongoing formalized inspection program at Turkey Point. The program was formally implemented as a result of Generic Letter 89-13, which recommended monitoring of service water systems to ensure that they would perform their safety-related function and based on experiences of biological fouling and corrosion throughout the industry. 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. This program has been effective in maintaining acceptable component cooling water heat exchanger performance and addressing biological fouling of strainers and heat exchangers. Various sections of the intake cooling water piping, basket strainers, and heat exchangers are periodically examined using nondestructive examination to determine the effects of corrosion and biological fouling. Results are evaluated and components are either repaired or replaced as required.

The program has been reviewed by the NRC during several inspections with no significant deviations or violations identified. FPL Quality Assurance surveillances and reviews have been performed with no significant deficiencies identified. Procedures and practices were enhanced as a result of the recommendations provided from these inspections.

Metallurgical analysis of removed component cooling water heat exchanger tubes, in 1991 and 1994, indicated that stress corrosion cracking was a potential root cause and, as a result, zinc anodes were installed and are inspected during tube cleaning. Analysis in 1996 of additional component cooling water heat exchanger tubes indicated that inside pitting was a potential failure mechanism and, as a result, a less abrasive cleaning tool was recommended. Both of these corrective actions have proven to be effective in minimizing repetitive failures.

A review of the Maintenance Rule database for the Intake Cooling Water and the Component Cooling Water Systems shows that the current aging management programs have supported system availability above the required performance criteria for the period from May 1996 through March 2000. There have been no functional failures attributed to aging or biological fouling of pressure-retaining components during that period.

Based on the above, the continued implementation of the Intake Cooling Water System Inspection Program provides reasonable assurance that the aging effects of corrosion and biological fouling will be managed, such that the components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis 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

Control Building Ventilation

Emergency Containment Filtration

Emergency Diesel Generators and Support Systems

Fire Protection

Instrument Air

Intake Cooling Water

Residual Heat Removal

Turbine Building Ventilation

Waste Disposal

STRUCTURES

Auxiliary Building

Emergency Diesel Generator Buildings

Turbine Building

Yard Structures

Scope

The Periodic Surveillance and Preventive Maintenance Program is credited for managing the aging effects of loss of material, cracking, fouling, loss of seal, and embrittlement for structures, systems, and components within the scope of license renewal. This program provides for visual inspection of selected surfaces of specific components and structural components, or alternatively their replacement/ refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program also includes leak inspections of limited portions of the Chemical and Volume Control Systems.

This program will be enhanced to address the scope of specific inspections and their documentation. Commitment dates associated with the enhancement of this program are contained in Appendix A.

Preventive Actions

No preventive actions are applicable to the aging effects being managed by this program.

Parameters Monitored or Inspected

Surface conditions of systems, structures, and components are monitored, through visual inspections, for corrosion, fouling, or in some cases leakage, during the performance of periodic maintenance. Based on inspection results, refurbishment is performed as required. For some equipment, periodic replacement is performed on a specified frequency.

This program will be enhanced with regard to the scope of specific inspections and their documentation.

Detection of Aging Effects

The aging effects of concern, loss of material, cracking, fouling, loss of seal, and embrittlement, will be detected by visual inspection of external surfaces for evidence of corrosion, cracking, leakage, or coating damage. For some equipment, aging effects are addressed by periodic replacement in lieu of visual inspection and refurbishment.

Monitoring and Trending

System, structure, and component inspections are performed periodically during preventive maintenance or surveillance activities. Alternatively, some components are replaced on a specified frequency. Inspection and replacement frequencies are adjusted as necessary based on the results of these activities and industry experience.

Acceptance Criteria

Acceptance criteria and guidelines are provided in the implementing procedures for the inspections, refurbishments, and replacements, as applicable.

Confirmation Process

Periodic inspection, refurbishment, and replacement activities performed under this program ensure that component and structure degradation is corrected in accordance with the corrective action program.

Operating Experience and Demonstration

The Periodic Surveillance and Preventive Maintenance Program is an established program at Turkey Point and has proven effective at maintaining the material condition of systems, structures, and components and detecting unsatisfactory conditions. The effectiveness of the program is supported by improved system, structure, and component material conditions and reliability, documented by internal and external industry assessments. The Periodic Surveillance and Preventive Maintenance Program is subject to periodic assessments to ensure effectiveness and continuous improvement.

Based on the above, the continued implementation of the Periodic Surveillance and Preventive Maintenance Program provides reasonable assurance that the aging effects of loss of material, cracking, fouling, loss of seal, and embrittlement will be managed, such that the components and structural components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.12 REACTOR VESSEL HEAD ALLOY 600 PENETRATION INSPECTION PROGRAM

As identified in Chapter 3, the Reactor Vessel Head Alloy 600 Penetration Inspection Program is credited for aging management of the reactor vessels in the Reactor Coolant Systems.

Scope

The Reactor Vessel Head Alloy 600 Penetration Inspection Program encompasses the Turkey Point Units 3 and 4 reactor vessel head Alloy 600 penetrations that are part of the Reactor Coolant System pressure boundary. This program manages the aging effect of cracking due to primary water stress corrosion. The program includes a one-time volumetric examination of selected Unit 4 reactor vessel head penetrations to detect crack initiation of reactor vessel head penetrations. Visual examination of the Units 3 and 4 reactor vessel head external surfaces during outages and the Boric Acid Wastage Surveillance Program are also utilized to manage cracking.

Preventive Actions

No actions are presently known that would prevent primary water stress corrosion cracking.

Parameters Monitored or Inspected

The program monitors the aging effect of primary water stress corrosion cracking on the intended function of the reactor vessel head penetrations by the detection of cracks and reactor coolant leakage.

Detection of Aging Effects

As noted above, a one-time volumetric examination of the inside diameter of selected penetrations of the Turkey Point Unit 4 reactor vessel head will be performed. Penetrations selected have been identified as being most susceptible to primary water stress corrosion cracking based on default values for yield strength. The results of this examination will be utilized to determine if additional examinations are required. At this time, it is anticipated that the volumetric examination would be an eddy current examination.

Visual inspection of the reactor vessel head to penetration area in accordance with the existing Boric Acid Wastage Surveillance Program is performed to detect any through wall coolant leakage from the reactor vessel head as evidenced by steam, boric acid crystals, or other indirect symptoms of fluid escape.

Monitoring and Trending

The volumetric examination will be performed prior to a 75% through wall flaw that is conservatively predicted to occur using the reference probability equivalent to D. C. Cook Unit 2 based on the Dominion Engineering CIRSE model. Follow up examinations will be determined based on the results of the initial examination and available industry data. The visual inspections of the reactor vessel head to penetration area are performed in accordance with the Boric Acid Wastage Surveillance Program.

Acceptance Criteria

The acceptance criteria for the volumetric examinations 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 visual inspections is no reactor vessel head pressure boundary leakage.

Confirmation Process

For the reactor vessel head penetrations, confirmation will include inspection of the repaired/replaced nozzle and pressure boundary verification in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program. Additional testing/examinations will be performed if required by the corrective action program.

Operating Experience and Demonstration

Turkey Point has been an active participant in Westinghouse Owners Group, Electric Power Research Institute, and Nuclear Energy Institute initiatives regarding cracking of Alloy 600 reactor vessel head penetrations. The Reactor Vessel Head Alloy 600 Penetration Inspection Program was created in response to NRC Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations" [Reference B-12]. This program has proven experience in addressing the concerns and requirements of the generic letter. The reactor vessel heads are currently subject to visual inspection for leakage. To date, Turkey Point has performed visual inspections for leakage on the top of the Turkey Point Units 3 and 4 reactor vessel heads as part of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the Boric Acid Wastage Surveillance Program. No evidence of leakage from the Alloy 600 reactor vessel head penetrations has been identified. Volumetric examinations have been performed at several plants, as identified in NEI Letter, "Response to NRC Request for Additional Information on Generic Letter 97-01, Project Number 689" [Reference B-13], and have been effective at detecting primary water stress corrosion cracking.

The NRC has concluded, in their letter dated January 27, 2000 [Reference B-14], that the Turkey Point Reactor Vessel Head Alloy 600 Penetration Inspection Program provides an acceptable basis for evaluating reactor vessel head penetrations.

Based on the above, the continued implementation of the Reactor Vessel Head Alloy 600 Penetration Inspection Program provides reasonable assurance that Reactor Coolant Systems components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.13 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.

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

The program documentation will be enhanced to integrate all aspects of the Reactor Vessel Integrity Program. Commitment dates associated with the enhancement of this program are contained in Appendix A.

3.2.13.1 REACTOR VESSEL SURVEILLANCE CAPSULE REMOVAL AND EVALUATION

Scope

This subprogram manages the aging effect of reduction in fracture toughness on the reactor vessel materials (beltline forgings and circumferential 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 program, 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 tests for irradiated specimens of reactor vessel forging and weld materials. Additionally, accumulated neutron fluence is monitored utilizing surveillance capsule dosimetry.

Detection of Aging Effects

Lower fracture toughness values than those predicted by extrapolation of historical empirical data 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, "Radiation Embrittlement of Reactor Vessel Materials" [Reference B-15], 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. The surveillance capsule withdrawal schedule is specified in Chapter 4 of the UFSAR Supplement provided in Appendix A of this Application. Turkey Point has sufficient surveillance capsules for the extended period of operation. 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, "Radiation Embrittlement of Reactor Vessel Materials" [Reference B-15], trend curves. Data that fall outside of the ±20% at the 1-sigma level 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 startup. This subprogram has been updated over the years and has provided experience in addressing reduction in fracture toughness. Turkey Point Units 3 and 4 pressure-temperature limit curves have been updated using results from the vessel surveillance capsule specimen evaluations. Turkey Point Units 3 and 4 have been evaluated to have values for RT_{PTS} that are within the acceptance criteria of 10 CFR 50.61.

3.2.13.2 FLUENCE AND UNCERTAINTY CALCULATIONS

Scope

This subprogram provides an accurate prediction of the reactor vessel accumulated fast neutron fluence values at the reactor vessel beltline forgings and circumferential 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 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" [Reference B-16], and are benchmarked using dosimetry results that are available from the Reactor Vessel Surveillance Capsule Removal and Evaluation Subprogram. Note that in the past, benchmarking has been supplemented by Draft NRC Regulatory Guide DG-1053 cavity (ex-vessel) dosimetry.

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, as supplemented by the cavity (ex-vessel) dosimetry. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained. Changes in fuel type or fuel loading pattern may also change the frequency of surveillance capsule withdrawal and the performance of neutron fluence and uncertainty calculations.

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. Present data of neutron fluence can be used to evaluate the accuracy of previous predictions.

Operating Experience and Demonstration

The neutron fluence and uncertainty calculations for Turkey Point Units 3 and 4 have been performed in accordance with the guidelines of the 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.

3.2.13.3 MONITORING EFFECTIVE FULL POWER YEARS

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 effective full power years.

Detection of Aging Effects

Effective full power year 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 effective full power years to be used in predicting the accumulated fast neutron fluence. Each Turkey Point unit is monitored to determine the effective full power years of operation. These data are used to validate the applicability of the pressure-temperature limit curves for the next operating cycle.

Acceptance Criteria

Calculated effective full power years shall not exceed the Technical Specification limit for the validity of the pressure-temperature limit curves.

Confirmation Process

The effective full power years of plant operation are based on reactor vessel incore power readings. Effective full power year values are determined by comparing the burnup to the thermal power calculated burnup. Data are collected for both Turkey

Point reactor vessels. The effective full power year calculations are verified each fuel cycle in accordance with the FPL Quality Assurance Program.

Operating Experience and Demonstration

The effective full power year values are determined by comparing the fuel burnup to the thermal power calculated burnup. The fuel burnup comparisons have been found to be within the expected accuracy.

3.2.13.4 PRESSURE-TEMPERATURE LIMIT CURVES

Scope

This subprogram provides pressure-temperature limit curves for the Turkey Point Units 3 and 4 reactor vessels to establish the Reactor Coolant System 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 Turkey Point 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 effective full power years. These curves shall be updated prior to exceeding the effective full power years 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

Turkey Point Units 3 and 4 utilize pressure-temperature limit curves that have been updated using the results of data obtained from the surveillance capsule specimens. 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 continued implementation of the Reactor Vessel Integrity Program provides an effective program for managing the aging effect of reduction in fracture toughness on the reactor vessel such that the components within the scope of license renewal will continue to perform their intended functions in accordance with the current licensing basis for the period of extended operation.

3.2.14 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.

Scope

The Steam Generator Integrity Program ensures that steam generator integrity is maintained under normal operating, transient, and postulated accident conditions. The program is structured to meet NEI 97-06, "Steam Generator Program Guidelines" [Reference B-17]. The program manages the aging effects of cracking and loss of material and includes the following essential elements:

- Inspection of steam generator tubing and tube plugs
- Steam generator secondary-side integrity inspections
- Tube integrity assessment
- Assessment of degradation mechanisms
- Primary-to-secondary leakage monitoring
- Primary and secondary chemistry control
- Sludge lancing
- Maintenance and repairs
- Foreign material exclusion

Preventive Actions

Preventive measures include primary and secondary chemistry control and sludge lancing. Primary and secondary chemistry control prevents cracking of steam generator tubes, as described in the steam generator aging management review. Sludge lancing is performed to prevent outside diameter pitting of steam generator tubing, which is associated with oxidizing conditions in the sludge piles.

Parameters Monitored or Inspected

The steam generator tube volumetric inspection technique detects flaw size and depth, or alternatively, remaining sound tube wall thickness. Primary-to-secondary leakage is monitored to verify tube integrity during plant operation. Steam generator tube integrity is assessed in accordance with the performance criteria provided in

NEI 97-06 [Reference B-17]. The performance criteria include structural, accident-induced leakage, and operational leakage limits. Inspection activities also monitor for leakage from the tube plugs.

Detection of Aging Effects

The extent and schedule of the inspections prescribed by the program are designed to ensure that flaws do not exceed established performance criteria. Problems with tube inspection -- e.g., failure to detect some flaws, uncertainty in flaw sizing, inaccuracy in flaw location, and inability to detect some cracks at locations with dents -- are considered in the Steam Generator Integrity Program. The extent and schedule of the inspections prescribed by the program are designed to ensure timely detection and replacement of leaking plugs. Detection of primary-to-secondary leakage during plant operation will identify flaw propagation caused by the aging mechanisms.

Monitoring and Trending

Required inspection intervals based on Technical Specification requirements are expected to provide timely detection of cracking, pitting, and wear. Required inspection intervals are intended to provide for timely detection of tube plug leakage. Daily monitoring of primary-to-secondary leakage will identify degradation of steam generator tubing.

Acceptance Criteria

Tubes are removed from service in accordance with the requirements of the Technical Specifications and the Steam Generator Integrity Program. Any tube plug leakage detected requires tube plug replacement. Identified primary-to-secondary leakage is compared with the limits allowed by the Technical Specifications.

Confirmation Process

Administrative procedures require follow-up testing and examinations to verify steam generator integrity prior to returning the steam generator to service.

Operating Experience and Demonstration

The Steam Generator Integrity Program has been effective in ensuring the 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.

The Steam Generator Integrity Program considers the guidance provided in NEI 97-06 [Reference B-17], which has undergone extensive industry and NRC review. This program is all-inclusive in managing steam generator tube bundle and internals degradation.

The Steam Generator Integrity Program has been reviewed by the NRC during several inspections and no deviations or violations have been identified. Quality Assurance surveillances and reviews have been performed with no deficiencies identified.

The current steam generator inspection activities have been evaluated against industry recommendations provided by EPRI and Westinghouse. The overall effectiveness of the program is supported by the excellent steam generator operating experience and favorable inspection results.

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 current licensing basis for the period of extended operation.

3.2.15 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 Building Ventilation

Auxiliary Feedwater and Condensate Storage

Chemical and Volume Control

Component Cooling Water

Containment Isolation

Containment Post Accident Monitoring and Control

Containment Spray

Control Building Ventilation

Emergency Containment Cooling

Emergency Diesel Generators and Support Systems

Feedwater and Blowdown

Instrument Air

Intake Cooling Water

Main Steam and Turbine Generators

Reactor Coolant

Residual Heat Removal

Safety Injection

Sample

Spent Fuel Pool Cooling

Turbine Building Ventilation

Waste Disposal

STRUCTURES

Auxiliary Building

Containments

Control Building

Diesel Driven Fire Pump Enclosure

Discharge Structure

Electrical Penetration Rooms

Emergency Diesel Generator Buildings

Fire Protection Monitoring Station

Intake Structure

Main Steam and Feedwater Platforms

Plant Vent Stack

Spent Fuel Storage and Handling

Turbine Building

Turbine Gantry Cranes

STRUCTURES (continued)

Yard Structures

Scope

The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties for selected systems, structures, and components within the scope of license renewal. The program provides for visual inspection and examination of accessible surfaces of specific systems, structures, and components, including welds and bolting.

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. For example, rust bleeding on an accessible surface of a concrete structure may be indicative of corrosion of inaccessible reinforcing steel embedded in the concrete.

This program will be enhanced by restructuring it to address inspection requirements to manage certain aging effects in accordance with 10 CFR 54, modifying the scope of specific inspections, and improving documentation requirements. Commitment dates associated with the enhancement of this program are contained in Appendix A.

Preventive Actions

External surfaces of carbon steel and cast iron valves, piping, and fittings, and specific stainless steel piping welds are coated to minimize corrosion and surfaces of steel structures and supports are also coated to minimize corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

Surface conditions of structures, system components/piping (including those exposed to a wetted environment), and supports are monitored through visual examinations to determine the existence of external corrosion and internal corrosion of certain ventilation equipment. Flexible connections are monitored for cracking due to embrittlement and ventilation heat exchangers are monitored for fouling. External surfaces of concrete are monitored through visual examination for exposed rebar, extensive rust bleeding, cracks that exhibit rust bleeding, and cracking of block walls and building roof seals. Leakage inspections of valves, piping, and fittings at limited locations of the Intake Cooling Water and Waste Disposal Systems are utilized to detect the presence of internal corrosion. Additionally, visual inspection of external surfaces of certain ventilation systems is used to assess internal system conditions. Inspection of protective coatings on specific stainless steel piping welds in outdoor locations will be performed to determine coating degradation. Inspection of weatherproofing material for deterioration is performed.

This program will be restructured and some enhancements to the scope of specific inspections and their documentation will be implemented.

Detection of Aging Effects

The aging effects of loss of material, crack initiation, fouling, loss of seal, and change in material properties are detected by visual inspection of external surfaces (including internal surfaces of certain ventilation equipment) for evidence of corrosion, cracking, leakage, fouling, or coatings damage.

Monitoring and Trending

Detailed structural and system/equipment 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 the inspections may be adjusted, as necessary, based on inspection results and industry experience. For insulated piping, a small sample of the sections of systems exposed to a wetted environment 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 (e.g., chilled water systems).

Acceptance Criteria

The results of the inspections and testing are evaluated in accordance with the acceptance criteria in the appropriate corrective action and administrative procedures.

Confirmation Process

Degradations are evaluated and entered into the corrective action program.

Operating Experience and Demonstration

Systems and piping/component support material condition inspections have been successfully performed at Turkey Point since the mid 1980s. The inspection requirements in support of the Maintenance Rule have been in effect since 1996, and have proven effective at maintaining systems/structures material condition and detecting unsatisfactory conditions that have resulted in effective corrective actions being taken.

The Systems and Structures Monitoring Program has been an ongoing program at Turkey Point and has been enhanced over the years to include the best practices recommended by the Institute of Nuclear Power Operations and other industry guidance. Additionally, the Systems and Structures Monitoring Program will continue to support implementation of the NRC Maintenance Rule (10 CFR 50.65).

The effectiveness of the Systems and Structures Monitoring Program is supported by the improved system and structure material conditions, documented by internal as well as external assessments of the last several years. Additionally, the Systems and Structures Monitoring Program is the subject of periodic internal and external assessments to insure effectiveness and continued improvement.

Based upon the above, the continued implementation of the Systems and Structures Monitoring Program provides reasonable assurance that the aging effects (loss of material, crack initiation, fouling, loss of seal, and change in material properties) will be managed such that systems and structures within the scope of License Renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

3.2.16 THIMBLE TUBE INSPECTION PROGRAM

As identified in Chapter 3, the Thimble Tube Inspection Program is credited for aging management of Unit 3 reactor vessel thimble tube N-05 in the Reactor Coolant Systems. The program was originally performed on all in-service thimble tubes for Units 3 and 4.

Scope

Based on previous inspections and the Time-Limited Aging Analysis results presented in Subsection 4.7.1, only thimble tube N-05 on Unit 3 will require inspection for the period of extended operation. The Thimble Tube Inspection Program manages the aging effect of loss of material due to fretting wear. The program utilizes eddy current test inspections to determine thimble tube wall thickness and predict wear rates for the early identification of potential thimble tube failure.

Preventive Actions

The thimble tube wall thickness obtained from eddy current test inspections will be used to predict thimble tube wear rates and enable corrective action before the thimble tube fails.

Parameters Monitored or Inspected

Thimble tube wall thickness.

Detection of Aging Effects

Thimble tube wall thinning will be determined utilizing eddy current testing inspections.

Monitoring and Trending

An eddy current test inspection will be performed on Unit 3 thimble tube N-05 in accordance with plant procedures. The data obtained from this inspection will be evaluated and the need for additional inspections will be determined.

Acceptance Criteria

The acceptance criteria for thimble tube wall thinning is less than 70% wall loss at the end of life.

Confirmation Process

Follow-up testing is performed to confirm satisfactory completion of corrective actions, if needed.

Operating Experience and Demonstration

The Thimble Tube Inspection Program was created and implemented in response to NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors" [Reference B-18]. This program has proven experience in addressing the requirements of the bulletin.

Wear of the thimble tubes is detected by the eddy current inspection. This technique is well known in the industry and has been used to detect imperfections in thimble tubes and other component tubing, such as steam generators, heat exchangers, etc. The eddy current inspection technique has been used to detect wall thinning on the thimble tubes with satisfactory results. The eddy current test inspection is performed in accordance with approved plant procedures by qualified personnel.

Based on the above, the implementation of the Thimble Tube Inspection Program provides reasonable assurance that the aging effects will be managed such that the thimble tubes will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.0 REFERENCES

B-1 "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," draft, U.S. Nuclear Regulatory Commission, April 21, 2000.

B-2 NEI 95-10, Revision 1, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Nuclear Energy Institute, January 2000.

B-3 FPL Letter, L-2000-010 to NRC, Turkey Point Unit 3, Docket No. 50-250, "Risk Informed Inservice Inspection Program," January 19, 2000.

B-4 Third Interval Inservice Inspection Program for Turkey Point Nuclear Units 3 and 4, ISI-PTN-3/4 Program, Revision 3, Turkey Point Nuclear Power Plants, Florida Power & Light Company, March 31, 1995.

B-5 Safety Evaluation by the Office of Nuclear Reactor Regulation Related to the Third Ten-Year Interval Inservice Inspection Program Plan and Associated Requests for Relief," U. S. Nuclear Regulatory Commission, March 31, 1995.

B-6 NEI 94-01, "Industry Guidelines for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J," Nuclear Energy Institute, July 26, 1995.

B-7 Regulatory Guide 1.35, Revision 3, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments," U.S. Nuclear Regulatory Commission, April 19, 1979.

B-8 Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," U.S. Nuclear Regulatory Commission, March 17, 1988.

B-9 R. J. Hovey (FPL) letter to U. S. Nuclear Regulatory Commission, "Response to Generic Letter 96-04 - Boraflex Degradation in Spent Fuel Pool Storage Racks," October 18, 1996.

B-10 Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," U.S. Nuclear Regulatory Commission, May 1989.

B-11 Generic Letter 89-13, "Service Water System Problems Affecting Safety Related Equipment," U.S. Nuclear Regulatory Commission, July 1989.

B-12 Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," U.S. Nuclear Regulatory Commission, April 1997.

B-13 David J. Modeen, (NEI) letter to Gus C. Lainas (NRC), "Response to NRC Request for Additional Information on Generic Letter 97-01, Project Number 689," December 11, 1998.

B-14 K. N. Jabbour (NRC) letter to T. F. Plunkett (FPL), "Generic Letter 97-01, Degradation of Control Rod Drive Mechanical Nozzle and Other Vessel Closure Head Penetrations: Review of the Responses for the Turkey Point Plant, Units 3 and 4," January 27, 2000.

B-15 Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," U.S. Nuclear Regulatory Commission, February 1986.

B-16 Draft Regulatory Guide DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U.S. Nuclear Regulatory Commission, June 1996.

B-17 NEI 97-06, "Steam Generator Program Guidelines," Nuclear Energy Institute, November 1997.

B-18 Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," U.S. Nuclear Regulatory Commission, July 26, 1988.

APPENDIX C

PROCESS FOR IDENTIFYING AGING EFFECTS REQUIRING MANAGEMENT FOR NON-CLASS 1 COMPONENTS

TABLE OF CONTENTS

1.0 INTRODUCTION

FPL utilized industry guidance developed by the 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 Turkey Point Units 3 and 4 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
- raw water – cooling canals
- raw water – city water
- raw water – floor drainage
- 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 ground water elevation)
- embedded/encased (in concrete)

For components that are submerged, the applicable internal environment listed above is 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) dated 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," Appendix B [Reference C-2], 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 and housings	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 [Reference C-3], 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 systems within the scope of license renewal:

aluminum	coated canvas	Monel
aluminum alloys	copper	neoprene
carbon steel (plain and galvanized)	copper alloys (admiralty brass, red brass, copper nickel, bronze, aluminum brass, aluminum bronze)	rubber
cast iron (ductile, white, malleable)	Inconel (alloy 600)	stainless steel (wrought and cast)
gray cast iron	low alloy steel	Worthite (nickel based alloy)

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 groups based on the chemistry of the water.

- <u>Treated water – primary</u> – Normal operating Reactor Coolant System chemistry
- <u>Treated water – secondary</u> – Normal operating secondary chemistry, including Main Steam, Feedwater, and Blowdown Systems
- <u>Treated water – borated</u> – Systems that contain borated water except those included in treated water – primary, including Chemical and Volume Control, Spent Fuel Cooling, and Emergency Core Cooling Systems
- <u>Treated water</u> – All other treated water systems, including Component Cooling Water, Emergency Diesel Generator Cooling, and Chilled Water Systems. These systems utilize corrosion inhibitors and, in some cases, biocides.

Aging effects for materials typically found in treated water environments are summarized in Section 6.1 of this appendix.

4.1.2 RAW WATER

For Turkey Point, raw water constitutes the salt water that comes from a closed cooling water canal system and is used for the main condensers and Intake Cooling Water System, and the city water used for the Fire Protection System. 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 groups based on the chemistry of the water.

- Raw water – cooling canals – Salt water used as the ultimate heat sink
- Raw water – city water – Potable water supplied to the water treatment plant and the Fire Protection System
- Raw water – floor drainage – 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 Section 6.2 of this appendix.

4.1.3 AIR/GAS

This includes atmospheric air, dry/filtered instrument air, nitrogen, carbon dioxide, hydrogen, helium, and Halon. Aging effects for materials typically found in air/gas environments are summarized in Section 6.3 of this appendix. 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, diesel fire pump, and standby steam generator feedwater pump. Aging effects for materials typically found in fuel oil environments are summarized in Section 6.4 of this appendix.

4.1.5 LUBRICATING OIL

This environment is the lubricating oil for emergency diesel generators, pumps, and other components. Aging effects for materials typically found in lubricating oil environments are summarized in Section 6.5 of this appendix.

4.2 EXTERNAL ENVIRONMENTS

4.2.1 OUTDOOR

The outdoor environment is characterized by moist, salt laden atmospheric air, temperature 30°F-95°F, humidity 5%-95%, and exposure to weather, including precipitation and wind. Aging effects for materials typically found in outdoor environments are summarized in Section 7.1 of this appendix.

4.2.2 INDOOR – NOT AIR CONDITIONED

This includes atmospheric air, a temperature of 104°F maximum , humidity 5%-95%, no exposure to weather. Aging effects for materials typically found in indoor – not air conditioned environments are summarized in Section 7.2 of this appendix.

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, and the humidity is 60%-80%. Aging effects for materials typically found in indoor – air conditioned environments are summarized in Section 7.3 of this appendix.

4.2.4 CONTAINMENT AIR

This includes atmospheric air, a temperature of 120°F maximum, humidity 5%-95%, radiation – total integrated dose rate 1 rad 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 Section 7.4 of this appendix.

Note: Safety-related equipment in the Containment has been analyzed to 122°F continuous and 125°F for 2 weeks/year.

4.2.5 BORATED WATER LEAKS

This environment includes exposure to leakage from borated water systems. Aging effects for materials exposed to borated water leak environments are summarized in Section 7.5 of this appendix.

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. Aging effects for materials typically found in buried environments are summarized in Section 7.6 of this appendix.

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 Section 7.7 of this appendix.

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 follows.

5.1 LOSS OF MATERIAL

Loss of material may be due to general corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion/corrosion, 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 component 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, cast austenitic stainless steel (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, such as salt spray, other than humidity.

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 Turkey Point 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 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 Turkey Point 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 designed to preclude these mechanisms. Additionally, these mechanisms are quite severe and would typically 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.

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.

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. 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 120°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. 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 pressurized water reactors 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.

5.2 CRACKING

Cracking is non-ductile failure of a component due to stress corrosion, fatigue, or embrittlement. The analysis of the potential for cracking due to metal fatigue is a Time-Limited Aging Analysis and is addressed in Section 4.3 of this Application.

Stress corrosion cracking (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 stress corrosion cracking are the presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb, and elevated temperature. For Turkey Point 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, stress corrosion cracking 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, exposure periods 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 exposed to high levels of contaminants (e.g., salt water) and only if the material is in a sensitized condition. Additionally, experience at Turkey Point has revealed susceptibility to TGSCC in the non-stress relieved heat affected zone regions of weld joints in schedule 10 large bore stainless steel pipe exposed to marine atmospheric conditions. However, most austenitic stainless steel and nickel base alloys are resistant to SCC at temperatures less than 140°F.

For carbon steels, stress corrosion cracking occurs most commonly in the presence of aqueous chlorides. Industry data do not indicate a significant problem of stress corrosion cracking of low strength carbon steels. For these reasons, stress corrosion cracking of carbon steels is not an aging effect requiring management.

Material fatigue resulting from vibration has been observed in the nuclear 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 could cause cracking of rubber, neoprene, or coated canvas materials at Turkey Point. 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 that could cause loss of heat transfer intended function at Turkey Point. Biological fouling can also lead to environmental conditions conducive to MIC. Fouling evaluated for Turkey Point 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

The loss of mechanical closure integrity is an aging effect associated with bolted mechanical closures that can result from the loss of pre-load due to cyclic loading, gasket creep, thermal or other effects, cracking, or loss of bolting material.

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 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 Turkey Point, there were no cases where gasket/seals are relied on to support component intended functions.

Loss of bolting material, on the other hand, can result in loss of a component's pressure boundary integrity and, thus, 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 pressurized water reactors 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.

Although there have been a few instances of cracking of bolting in the industry due to SCC, these have been attributed to high yield stress materials and contaminants, such as the use of lubricants containing MoS_2. For quenched and tempered low alloy steels (e.g., SA193 Grade B7) used for closure bolting material, susceptibility to SCC is controlled by yield strength. Additionally, operating experience and existing data indicate that SCC failure should not be a significant issue for the bolting materials of SA193 Grade B7.

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 crystallization 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 Turkey Point 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 Turkey Point plant systems operate below the temperature at which stress relaxation occurs and, thus, are not susceptible to stress relaxation.

6.0 AGING EFFECTS REQUIRING MANAGEMENT FOR INTERNAL ENVIRONMENTS

6.1 TREATED WATER

6.1.1 ATTRIBUTES OF TREATED WATER ENVIRONMENTS

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 could be deaerated and can include corrosion inhibitors, biocides, boric acid, or some combination of these treatments. In the determination of aging effects, steam is considered treated water. Although treated water was evaluated as a single environment, for the purposes of clarity in the Application, treated water has been divided into the following groups:

- Treated water – primary – Normal operating Reactor Coolant System chemistry
- Treated water – secondary – Normal operating secondary chemistry, including Main Steam and Feedwater 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, and Emergency Core Cooling Systems
- Treated water – All other treated water systems, including Component Cooling Water, Emergency Diesel Generator Cooling, and Chilled Water Systems

Chemistry requirements for the treated water are stringent since treated water is used for the Reactor Coolant System, and various secondary and auxiliary systems in which high quality is required.

The chemistry for all treated water that is used in cooling water systems includes a corrosion inhibitor, with the exception of the water associated with steam generator makeup, such as condensate storage and demineralized water storage.

6.1.2 MATERIALS USED IN TREATED WATER ENVIRONMENTS

The following materials are exposed to an internal treated water environment:

admiralty brass	cast iron	low alloy steel
aluminum brass	copper nickel	red brass
brass	copper	rubber
bronze	gray cast iron	stainless steel
carbon steel	Inconel	Worthite (nickel based alloy)

6.1.3 AGING EFFECTS IN TREATED WATER ENVIRONMENTS

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with treated water systems.

6.1.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for low alloy steel, cast iron, carbon steel, and gray cast iron in treated water environments.

Loss of material due to pitting corrosion is an aging effect requiring management for admiralty brass, low alloy steel, aluminum brass, brass, carbon steel, cast iron, gray cast iron, Inconel, stainless steel, and Worthite in treated water environments.

Loss of material due to galvanic corrosion is an aging effect requiring management for admiralty brass, brass, carbon steel, cast iron, and copper in treated water environments when coupled with material having higher electrical potential.

Loss of material due to erosion/corrosion is an aging effect requiring management for carbon steel in treated water under certain conditions. Fluid conditions in the Main Steam, Main Feedwater, and Steam Generator Blowdown Systems can lead to erosion/corrosion.

Loss of material due to microbiologically influenced corrosion is an aging effect requiring management for admiralty brass, aluminum brass, brass, carbon steel, cast iron, copper, copper nickel, gray cast iron, Inconel, red brass, stainless steel, and Worthite (nickel based alloy).

Loss of material due to selective leaching is an aging effect requiring management for admiralty brass, brass, and gray cast iron in treated water environments.

6.1.3.2 CRACKING

Cracking due to stress corrosion, intergranular stress corrosion, embrittlement (rubber products), and high-cycle fatigue of stainless steel materials is an aging effect requiring management in treated water environments. Cracking resulting from fatigue is precluded by design. However, an exception identified is the charging pump fluid blocks that are susceptible to high-cycle fatigue.

A review of NRC Bulletin 79-17, "Pipe Cracks in Stagnant Borated Water Systems at PWR Plants," identified stress corrosion cracking as a potential aging mechanism in stainless steel piping of safety-related systems containing stagnant borated water. Turkey Point operating experience, in the early 1990s, identified through wall leakage in heat traced boric acid piping and components. Therefore, SCC is considered an aging mechanism requiring management for stainless steel piping and components associated with the boric acid supply to the charging pump suction header. Note that these piping and components are no longer heat traced or insulated.

6.1.3.3 FOULING

Biological and particulate fouling of admiralty brass, aluminum brass, Inconel, red brass, gray cast iron, and stainless steel heat exchanger tubes is an aging effect requiring management in treated water environments.

6.1.4 INDUSTRY EXPERIENCE WITH TREATED WATER ENVIRONMENTS

To validate the aging effects requiring management for components exposed to a treated water internal operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

6.2 RAW WATER

6.2.1 ATTRIBUTES OF RAW WATER ENVIRONMENTS

The majority of the raw water for Turkey Point is from the city water source, the Cooling Water Canal System, or building floor drains. In general, the water has been rough filtered. The city water system is a potable water system and the Cooling Water Canal System is saltwater system.

6.2.2 MATERIALS USED IN RAW WATER ENVIRONMENTS

Materials within the scope of license renewal at Turkey Point that are exposed to raw water include the following:

aluminum brass	carbon steel - galvanized	rubber
aluminum bronze	cast iron	stainless steel
bronze	gray cast iron	Monel
carbon steel	copper nickel	

6.2.3 AGING EFFECTS IN RAW WATER ENVIRONMENTS

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with raw water systems.

6.2.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for cast iron and carbon steel in raw water environments.

Loss of material due to pitting corrosion is an aging effect requiring management for aluminum bronze, carbon steel, cast iron, Monel, and stainless steel in raw water environments.

Loss of material due to galvanic corrosion is an aging effect requiring management for carbon steel and cast iron in raw water environments when coupled with materials having higher electrical potential.

Loss of material due to crevice corrosion is an aging effect requiring management for aluminum bronze, bronze, carbon steel, cast iron, copper nickel, Monel, and stainless steel in raw water environments.

Loss of material due to microbiologically influenced corrosion is an aging effect requiring management for aluminum bronze, bronze, carbon steel, cast iron, copper nickel, Monel, and stainless steel in raw water environments.

Loss of material due to selective leaching is an aging effect requiring management for aluminum bronze and gray cast iron in raw water environments.

6.2.3.2 CRACKING

Cracking due to embrittlement is an aging effect requiring management for rubber in raw water environments.

6.2.3.3 FOULING

Biological and particulate fouling of copper alloy heat exchanger tubes is an aging effect requiring management in raw water environments. Additionally, particulate fouling (clogging) of stainless steel floor drains is an aging effect requiring management.

6.2.4 INDUSTRY EXPERIENCE WITH RAW WATER ENVIRONMENTS

To validate the aging effects requiring management for components exposed to a raw water internal operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

6.3 AIR/GAS

6.3.1 ATTRIBUTES OF AN AIR/GAS ENVIRONMENT

The environments included in this category include atmospheric air, dry/filtered instrument air, nitrogen, carbon dioxide, hydrogen, and Halon. In some cases, a wetted environment may exist due to condensation (e.g., at an air conditioning air handler housing). For these cases, the environment description is amended and aging effects addressed accordingly. The various gaseous environments addressed in this discussion are described below.

6.3.1.1 AIR

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.

6.3.1.2 NITROGEN

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.

6.3.1.3 CARBON DIOXIDE

Carbon dioxide is a colorless, odorless incombustible gas. The carbon dioxide system contains dry carbon dioxide in gaseous form. Without the presence of moisture, the gaseous carbon dioxide is not a significant contributor to corrosion or other aging effects.

6.3.1.4 HYDROGEN

Hydrogen is a colorless, odorless gas.

6.3.1.5 HALON

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.

6.3.2 MATERIALS USED IN AN AIR/GAS ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to air/gas contain the following materials:

aluminum	carbon steel	copper
aluminum alloys	carbon steel - galvanized	rubber
brass	cast iron	stainless steel
bronze	coated canvas	

6.3.3 AGING EFFECTS IN AN AIR/GAS ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with air/gas systems.

6.3.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for carbon steel and cast iron in atmospheric air/gas environments. Loss of material due to general corrosion is an aging effect requiring management for galvanized carbon steel in wetted air/gas environments, such as upstream of the air dryers in the Instrument Air System.

Loss of material due to pitting corrosion is an aging effect requiring management for carbon steel and stainless steel in atmospheric air/gas environments. Loss of material due to general corrosion is an aging effect requiring management for galvanized carbon steel in wetted air/gas environments, such as upstream of the air dryers in the Instrument Air System.

Loss of material due to galvanic corrosion is an aging effect requiring management for carbon steel, galvanized carbon steel, and copper alloys in wetted air/gas environments, such as upstream of the air dryers in the Instrument Air System or some heat exchangers in the ventilation systems.

Loss of material due to crevice corrosion is an aging effect requiring management for carbon steel in wetted air/gas environments.

6.3.3.2 CRACKING

Cracking due to fatigue is an aging effect requiring management for stainless steel in air/gas environments only for the emergency diesel generator exhaust expansion joints.

Cracking due to embrittlement is an aging effect requiring management for coated canvas and rubber in air/gas environments.

6.3.4 INDUSTRY EXPERIENCE WITH AIR/GAS ENVIRONMENT

To validate the aging effects requiring management for components exposed to an air/gas internal operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

6.4 FUEL OIL

6.4.1 ATTRIBUTES OF A FUEL OIL ENVIRONMENT

Fuel oil within the scope of license renewal is No. 2 diesel oil. Diesel fuel oil is delivered to Turkey Point in tanker trucks and is stored in large tanks to provide an on-site 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. Fuel oil is also supplied to the diesel driven fire pump and the standby steam generator feedwater pump.

6.4.2 MATERIALS USED IN A FUEL OIL ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to fuel oil contain the following materials:

carbon steel	copper
cast iron	stainless steel

6.4.3 AGING EFFECTS IN A FUEL OIL ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with fuel oil systems.

6.4.3.1 LOSS OF MATERIAL

Loss of material due to microbiologically influenced corrosion is an aging effect requiring management for carbon steel, cast iron, copper, and stainless steel in fuel oil environments.

6.4.4 INDUSTRY EXPERIENCE WITH A FUEL OIL ENVIRONMENT

To validate the aging effects requiring management for components exposed to a fuel oil internal operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

6.5 LUBRICATING OIL

6.5.1 ATTRIBUTES OF A LUBRICATING OIL ENVIRONMENT

Lubricating oils within the scope of license renewal are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication:

6.5.2 MATERIALS USED IN A LUBRICATING OIL ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to lubricating oil contain the following materials:

admiralty brass	copper	stainless steel
carbon steel	gray cast iron	
cast iron	red brass	

6.5.3 AGING EFFECTS IN A LUBRICATING OIL ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. No aging effects requiring management for non-Class 1 components in a lubricating oil environment have been identified.

6.5.4 INDUSTRY EXPERIENCE WITH A LUBRICATING OIL ENVIRONMENT

To validate the aging effects requiring management for components exposed to a lubricating oil internal operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.0 AGING EFFECTS REQUIRING MANAGEMENT FOR EXTERNAL ENVIRONMENTS

7.1 OUTDOOR

7.1.1 ATTRIBUTES OF AN OUTDOOR ENVIRONMENT

The outdoor environment consists of moist, salt laden atmospheric air, temperature 30°F-95°F, humidity 5%-95%, and exposure to weather, including precipitation and wind.

Note that a component is considered susceptible to a wetted environment when it is submerged, has the potential to pool water, or is subject to external condensation.

7.1.2 MATERIALS USED IN AN OUTDOOR ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to an outdoor environment contain the following materials:

aluminum	carbon steel	low alloy steel
aluminum bronze	carbon steel - galvanized	Monel
brass	cast iron	rubber
bronze	copper nickel	stainless steel

7.1.3 AGING EFFECTS IN AN OUTDOOR ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with materials in an outdoor environment.

7.1.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for low alloy steel, carbon steel, and cast iron in outdoor environments.

Loss of material due to pitting corrosion is an aging effect requiring management for low alloy steel, carbon steel, cast iron, and, in some locations, stainless steel in outdoor environments.

Loss of material due to galvanic corrosion is an aging effect requiring management for carbon steel and cast iron in outdoor wetted environments.

Loss of material due to crevice corrosion is an aging effect requiring management for carbon steel and cast iron in outdoor wetted environments.

Loss of material due to microbiologically influenced corrosion is an aging effect requiring management for carbon steel and cast iron in outdoor wetted environments.

7.1.3.2 CRACKING

Cracking due to stress corrosion is an aging effect requiring management for stainless steel in outdoor environments for large bore thin wall pipe, as discussed in Section 5.2. Cracking of rubber due to embrittlement is an aging effect requiring management.

7.1.3.3 FOULING

Fouling due to particulates is an aging effect requiring management for aluminum heat exchanger fins of the Turbine Building Ventilation System.

7.1.4 INDUSTRY EXPERIENCE WITH AN OUTDOOR ENVIRONMENT

To validate the aging effects requiring management for components exposed to an outdoor external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.2 INDOOR – NOT AIR CONDITIONED

7.2.1 ATTRIBUTES OF AN INDOOR – NOT AIR CONDITIONED ENVIRONMENT

The indoor – not air conditioned environment consists of atmospheric air, a temperature of 104°F maximum, humidity 5%-95%, and no exposure to weather.

7.2.2 MATERIALS USED IN AN INDOOR – NOT AIR CONDITIONED ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to an indoor – not air conditioned environment contain the following materials:

aluminum	carbon steel - galvanized	rubber
aluminum alloys	cast iron	stainless steel
brass	copper	Worthite (nickel based alloy)
carbon steel	gray cast iron	

7.2.3 AGING EFFECTS IN AN INDOOR – NOT AIR CONDITIONED ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with materials in an indoor-not air conditioned environment.

7.2.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for carbon steel and cast iron in indoor – not air conditioned environments.

Loss of material due to pitting corrosion is an aging effect requiring management for carbon steel and cast iron in indoor – not air conditioned environments.

7.2.3.2 CRACKING

Cracking due to stress corrosion is an aging effect requiring management for stainless steel piping and components associated with the boric acid supply to the charging pump supply header that was previously heat traced.

Cracking due to fatigue is an aging effect requiring management for stainless steel in isolated cases, such as the emergency diesel generator expansion joints.

Cracking due to embrittlement is an aging effect requiring management for rubber in indoor – not air conditioned environments.

7.2.4 INDUSTRY EXPERIENCE WITH AN INDOOR – NOT AIR CONDITIONED ENVIRONMENT

To validate the aging effects requiring management for components exposed to an indoor – not air conditioned external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.3 INDOOR – AIR CONDITIONED

7.3.1 ATTRIBUTES OF AN INDOOR – AIR CONDITIONED ENVIRONMENT

The indoor – air conditioned environment consists of atmospheric air with a temperature/humidity range dependent on the building/room and no exposure to weather. Typical temperature is 70°F and humidity is 60%-80%.

Note that a component is considered susceptible to a wetted environment when it is submerged, has the potential to pool water, or is subject to external condensation.

7.3.2 MATERIALS USED IN AN INDOOR – AIR CONDITIONED ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to an indoor – air-conditioned environment contain the following materials:

aluminum	carbon steel - galvanized	copper
carbon steel	coated canvas	stainless steel

7.3.3 AGING EFFECTS IN AN INDOOR – AIR-CONDITIONED ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with materials in a wetted indoor-air conditioned environment.

7.3.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for carbon steel and copper when wetted in indoor – air conditioned environments.

Loss of material due to pitting corrosion is an aging effect requiring management for carbon steel, copper, and stainless steel when wetted in indoor – air conditioned environments.

Loss of material due to galvanic corrosion is an aging effect requiring management for aluminum, carbon steel, and copper when wetted in indoor – air conditioned environments.

Loss of material due to microbiologically influenced corrosion is an aging effect requiring management for carbon steel when wetted in indoor – air conditioned environments.

7.3.3.2 CRACKING

Cracking due to embrittlement is an aging effect requiring management for coated canvas and rubber in indoor – air conditioned environments.

7.3.4 INDUSTRY EXPERIENCE WITH AN INDOOR – AIR CONDITIONED ENVIRONMENT

To validate the aging effects requiring management for components exposed to an indoor – air conditioned external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.4 CONTAINMENT AIR

7.4.1 ATTRIBUTES OF A CONTAINMENT AIR ENVIRONMENT

The containment air consists of atmospheric air, a temperature of 120°F maximum, humidity 5%-95%, radiation total integrated dose rate of 1 rad/hr (excluding equipment located inside the reactor cavity), and no exposure to weather.

Safety-related equipment in the Containment has been analyzed to 122°F continuous and 125°F for two weeks/year.

Note that a component is considered susceptible to a wetted environment when it is submerged, has the potential to pool water, or is subject to external condensation.

7.4.2 MATERIALS USED IN A CONTAINMENT AIR ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to a containment air environment contain the following materials:

admiralty brass	bronze	coated canvas
aluminum	carbon steel	neoprene
brass	carbon steel - galvanized	stainless steel

7.4.3 AGING EFFECTS IN A CONTAINMENT AIR ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with materials in a containment air environment.

7.4.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for carbon steel in containment environments and admiralty brass when wetted in containment environments.

Loss of material due to pitting corrosion is an aging effect requiring management for carbon steel in containment environments and admiralty brass and stainless steel when wetted in containment environments.

Loss of material due to crevice corrosion is an aging effect requiring management for carbon steel when wetted in containment environments.

Loss of material due to microbiologically influenced corrosion is an aging effect requiring management for carbon steel when wetted in containment environments.

7.4.3.2 CRACKING

Cracking due to embrittlement is an aging effect requiring management for coated canvas and neoprene in containment environments.

7.4.3.3 FOULING

Fouling due to particulates is an aging effect requiring management for aluminum heat exchanger fins in containment environments.

7.4.4 INDUSTRY EXPERIENCE WITH A CONTAINMENT AIR ENVIRONMENT

To validate the aging effects requiring management for components exposed to a containment air external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.5 BORATED WATER LEAKS

7.5.1 ATTRIBUTES OF A BORATED WATER LEAKS ENVIRONMENT

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.

7.5.2 MATERIALS USED IN A BORATED WATER LEAKS ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to a borated water leaks environment contain the following materials:

carbon steel	cast iron
carbon steel - galvanized	low alloy steel

7.5.3 AGING EFFECTS IN A BORATED WATER LEAKS ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with materials exposed to a borated water environment.

7.5.3.1 LOSS OF MATERIAL

Loss of material due to aggressive chemical attack is an aging effect requiring management for carbon steel, low alloy steel, cast iron, and galvanized carbon steel susceptible to potential borated water leaks.

7.5.3.2 LOSS OF MECHANICAL CLOSURE INTEGRITY

Loss of mechanical closure integrity due to aggressive chemical attack is an aging effect requiring management for mechanical closure carbon and low alloy steel bolting susceptible to potential borated water leaks. Components located in proximity to borated water systems are considered susceptible.

7.5.4 INDUSTRY EXPERIENCE WITH A BORATED WATER LEAKS ENVIRONMENT

To validate the aging effects requiring management for components exposed to a borated water leaks external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.6 BURIED

7.6.1 ATTRIBUTES OF A BURIED ENVIRONMENT

The buried environment applies to components buried in the soil and exposed to soil and groundwater. The soil and groundwater are untreated and could be corrosive materials. The factors affecting corrosiveness are moisture, pH, permeability of soil for water and air, oxygen, salts, stray currents, and biological organisms. Buried components are assumed susceptible to corrosion.

7.6.2 MATERIALS USED IN A BURIED ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to a buried environment contain the following materials:

carbon steel	gray cast iron
cast iron	

7.6.3 AGING EFFECTS IN A BURIED ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. Below is a summary of aging effects requiring management associated with materials in a buried environment.

7.6.3.1 LOSS OF MATERIAL

Loss of material due to general corrosion is an aging effect requiring management for carbon steel and cast iron in buried environments.

Loss of material due to pitting corrosion is an aging effect requiring management for carbon steel and cast iron in buried environments.

Loss of material due to galvanic corrosion is an aging effect requiring management for carbon steel and cast iron in buried environments.

Loss of material due to crevice corrosion is an aging effect requiring management for carbon steel and cast iron in buried environments.

Loss of material due to selective leaching is an aging effect requiring management for gray cast iron in buried environments.

7.6.4 INDUSTRY EXPERIENCE WITH A BURIED ENVIRONMENT

To validate the aging effects requiring management for components exposed to a buried external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

7.7 EMBEDDED/ENCASED

7.7.1 ATTRIBUTES OF AN EMBEDDED/ENCASED ENVIRONMENT

An embedded/encased environment involves steel piping embedded or encased in concrete.

7.7.2 MATERIALS USED IN AN EMBEDDED/ENCASED ENVIRONMENT

The non-Class 1 components within the scope of license renewal exposed to an embedded/encased environment contain the following material:

steel

7.7.3 AGING EFFECTS IN AN EMBEDDED/ENCASED ENVIRONMENT

Section 5.0 provides a discussion of the potential aging effects based on materials and environments. Aging effects are considered to require management if the effects could cause a component to lose its ability to perform an intended function during the period of extended operation. No aging effects requiring management for non-Class 1 components in an embedded/encased environment have been identified.

7.7.4 INDUSTRY EXPERIENCE WITH AN EMBEDDED/ENCASED ENVIRONMENT

To validate the aging effects requiring management for components exposed to an embedded/encased external operating environment, industry experience was reviewed. The survey of industry experience included a review of NRC generic communications and NUREG documents. No aging effects were identified in these documents beyond those discussed in this section.

8.0 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 1, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Nuclear Energy Institute, January 2000.

C-3 C. I. Grimes (NRC) letter to D. J. Walters (NEI), "License Renewal Issue No. 98-12, "Consumables," March 10, 2000.

APPENDIX D

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 Turkey Point License Renewal Application and Technical Specifications, no license amendment requests for Turkey Point Units 3 and 4 Technical Specifications are being submitted with this Application.