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August 20, 2015

United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Subject: License Amendment Request to Revise Technical Specifications Section 5.5.6 for Extension of Type A and Type C Leak Rate Test Frequencies

James A. FitzPatrick Nuclear Power Plant
Docket No. 50-333
License No. DPR-59

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Entergy Nuclear Operations, Inc. (Entergy) is submitting a request for a License Amendment to the Technical Specifications (TS) for the James A. FitzPatrick Nuclear Power Plant (JAF).

The proposed TS change would revise the TS 5.5.6 Primary Containment Leak Rate Testing Program to allow permanent extension of the Type A Primary Containment Integrated Leak Rate Test (ILRT) interval to 15 years and to allow extension of Type C Local Leak Rate Test (LLRT) testing interval up to 75 months.

The proposed change has been reviewed by the JAF On-site Safety Review Committee (OSRC).

Attachment 1 provides a description and assessment of the proposed changes. Attachment 2 provides the existing TS pages marked up to show the proposed changes. Attachment 3 provides revised (clean) TS pages. Attachment 4 contains the risk assessment for JAF supporting the ILRT (Type A) permanent extension request.

Approval of the proposed amendment is requested by August 20, 2016 in order to support the extension of a number of Type C LLRT. Once approved, this amendment shall be implemented within 120 days.

Entergy has reviewed the proposed amendment in accordance with 10 CFR 50.92 and concludes it does not involve a significant hazards consideration. In accordance with 10 CFR 50.91, a copy of this application, with attachments, is being provided to the designated New York State Official.

No commitments are contained in this submittal. If you should have any questions regarding this submittal, please contact Mr. Chris M. Adner, Regulatory Assurance Manager, at 315-349-6766.

I declare under penalty of perjury that the foregoing is true and correct. Executed on August 20, 2015.

Sincerely,

For B. Sullivan as Acting SVP

Brian R. Sullivan/Timothy C. Peter
Site Vice President

BRS/CMA/dc

Attachments:
1. Evaluation of Proposed Change
2. Proposed Technical Specification Changes (Markup)
3. Revised Technical Specification Changes (Clean)
4. JAFNPP Evaluation of Risk Significance of Permanent ILRT Extension

cc:

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JAFP-15-0098

Attachment 1

Evaluation of Proposed Change

(77 Pages)

ATTACHMENT 1

EVALUATION OF PROPOSED CHANGE

SUBJECT: Revise Technical Specification Section 5.5.6 for Permanent Extension of Type A and Type C Leak Rate Test Frequencies

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Attachments:
2. Proposed Technical Specification 5.5.6 (Markup)
3. Proposed Technical Specification 5.5.6 (Clean)
4. Evaluation of Risk Significance of Permanent ILRT Extension

1.0 SUMMARY DESCRIPTION

This evaluation supports a request to amend Renewed Facility Operating License DPR-59 for James A. FitzPatrick Nuclear Power Plant (JAF). The proposed changes would revise the Operating License by amending Technical Specification (TS) Section 5.5.6, "Primary Containment Leakage Rate Testing Program." The proposed changes to the Technical Specification contained herein would revise JAF TS 5.5.6 by replacing the reference to Regulatory Guide (RG) 1.163 (Reference 1) with a reference to Nuclear Energy Institute (NEI) Topical Report NEI 94-01, Revision 3-A, dated July 2012 (Reference 2) and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008 (Reference 8), as the implementation documents used by JAF to implement the JAF performance-based leakage testing program in accordance with Option B of 10 CFR Part 50, Appendix J.

The proposed change would allow the following:

- Increase in the existing integrated leak rate test (ILRT) program test interval to 15 years.
- Allow an extension from the 60-month frequency currently permitted by Option B to a 75-month frequency for Type C leakage rate testing of selected components.
- Adopt the use of ANSI/ANS 56.8-2002, Containment System Leakage Testing Requirements.
- Adopt a more conservative grace interval of 9 months, for Type B and Type C tests in accordance with Nuclear Energy Institute (NEI) Topical Report NEI 94-01, revision 3-A.

2.0 DETAILED DESCRIPTION

JAF TS 5.5.6, "Primary Containment Leakage Rate Testing Program," currently states, in part:

> "This program implements the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exceptions:
>
> - NEI 94 -01-1995. Section 9.2.3: The first Type A test performed after the March 7, 1995 Type A test shall be performed no later than March 7, 2010.
> - Type C testing of valves not isolable from the containment free air space may be accomplished by pressurization in the reverse direction, provided that testing in this manner provides equivalent or more conservative results

than testing in the accident direction. If potential atmospheric leakage paths (e.g., valve stem packing) are not subjected to test pressure, the portions of the valve not exposed to test pressure shall be subjected to leakage rate measurement during regularly scheduled Type A testing. A list of these valves, the leakage rate measurement method, and the acceptance criteria, shall be contained in the Program."

The proposed changes to JAF TS 5.5.6 will remove the first TS exception addressing the Type A test frequency and replace the reference to RG 1.163 with a reference to NEI Topical Report NEI 94-01 Revisions 2-A and 3-A. The proposed change will revise TS 5.5.6 to state, in part:

"This program implements the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, as modified by the following exception:

- Type C testing of valves not isolable from the containment free air space may be accomplished by pressurization in the reverse direction, provided that testing in this manner provides equivalent or more conservative results than testing in the accident direction. If potential atmospheric leakage paths (e.g., valve stem packing) are not subjected to test pressure, the portions of the valve not exposed to test pressure shall be subjected to leakage rate measurement during regularly scheduled Type A testing. A list of these valves, the leakage rate measurement method, and the acceptance criteria, shall be contained in the Program."

A markup of the proposed change to Technical Specification 5.5.6 is provided in Attachment 2.

Attachment 4 contains the plant specific risk assessment conducted to support this proposed change. This risk assessment followed the guidelines of NRC RG 1.174, Revision 2 (Reference 3) and NRC RG 1.200, Revision 2 (Reference 4). The risk assessment concluded that the increase in risk as a result of this proposed change is small and is well within established guidelines.

3.0 TECHNICAL EVALUATION

3.1 Description of Primary Containment System

The Primary Containment System is of the pressure suppression type and houses the reactor vessel, the reactor recirculating loops, and other branch connections of the Reactor Coolant System. The system includes a drywell, a pressure suppression

chamber (torus) which stores a large volume of water (pressure suppression pool), the Connecting Vent System between the drywell and the pressure suppression pool, isolation valves, the Vacuum Relief System, and the RHR subsystems for containment cooling.

In the event of a Reactor Coolant Pressure Boundary failure within the drywell, reactor water and steam are released into the drywell air space. The resulting increased drywell pressure forces a mixture of noncondensable gases, steam and water through the connecting vents into the pressure suppression pool. The steam condenses rapidly in the pressure suppression pool resulting in rapid pressure reduction in the drywell. Noncondensable gases transferred during reactor blowdown to the pressure suppression chamber pressurize the chamber and are subsequently vented back to the drywell through the Vacuum Relief System as the pressure in the drywell drops below that in the pressure suppression chamber.

The RHR subsystems for containment cooling are provided to remove heat from the pressure suppression pool to permit continuous cooling of the primary containment under the postulated Design Basis Accident conditions for which the Primary Containment System is assumed to be functional. A Containment Flooding System is provided, if required, for post-accident recovery following a Loss-of-Coolant Accident. It permits removal of the decay heat from the reactor and makes indefinite operation of the Emergency Core Cooling Systems unnecessary. Isolation valves are provided to ensure containment of radioactive material within the primary containment which might be released from the reactor to the primary containment during the course of an accident. Service equipment such as the Primary Containment Cooling and Ventilation System is provided to maintain the containment within its design parameters during normal operation.

The design, fabrication, inspection and testing of the primary containment vessel conform to the requirements for Class B vessels in the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code for Nuclear Vessels, including the 1968 Summer Addenda.

3.1.1 Primary Containment Leakage Monitoring

The primary containment leakage is continuously monitored for gross leakage during plant operation while it is inerted. This is accomplished by review of the inerting system makeup requirements in the following manner:

1. The containment is pressurized or evacuated to greater than or equal to 1.7 psi differential.

2. Over a period of time, leakage from the containment causes a change in pressure.

3. When pressure reaches a prescribed limit, the original pressure is re-established.

4. The gas flow is metered to provide a direct measure of containment leakage over the period since the last charge.

5. An immediate investigation is made if abnormal leakage is noted.

There is no specific instrumentation installed to detect leakage from the drywell. The only result of leakage from the drywell to the suppression pool would be to reduce steam condensation during a LOCA. However, there is considerable margin between the calculated and design pressure of the suppression pool so that 100 percent steam condensation is not required.

Provisions are made so that integrated containment leakage rate tests may be periodically performed during periods of reactor shutdown.

3.1.2 Drywell

The drywell is a steel pressure vessel with a spherical lower portion 65 ft. in diameter, and a cylindrical upper portion 35 ft-7 inches in diameter. The overall height is approximately 111 ft-5 1/4 inch. The drywell is closed at its top by a curved head 30 ft-2 inches in diameter attached to the cylindrical neck by bolting flanges.

The drywell is designed for an internal pressure of 56 psig coincident with a maximum design temperature of 309 F with applicable dead weight and seismic loads. Thus, in accordance with the ASME Code, Section III, the maximum allowable drywell pressure is 62 psig. Thermal stresses in the steel shell due to longitudinal temperature gradients are taken into account in the design. The drywell is also designed for 2.0 psig external pressure at 309 F.

The lowest service metal temperature, as defined in the ASME Code, is 30 F.

The drywell is enclosed in reinforced concrete for shielding purposes. Above the sand filled transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 inches. Below the sand filled transition zone the concrete is in direct contact with the outside of the steel shell. Shielding over the top of the drywell is provided by removable, segmented, reinforced concrete shield plugs.

In addition to the drywell head, two double-door air locks, two bolted equipment hatches and one CRD removal hatch are provided for access to the drywell. One of the air locks is mounted concentrically to an equipment hatch. The locking mechanisms on each air lock door are designed so that a tight seal is maintained when the doors are subjected to design pressures. The doors in each air lock are mechanically interlocked so that neither door may be operated unless the other door is closed and locked. The drywell head and equipment and CRD removal hatch covers are bolted in place and sealed with double gaskets which have provisions for interspace pressure testing.

3.1.3 Pressure Suppression Chamber and Vent System

The pressure suppression pool, which is contained in the pressure suppression chamber, is designed to serve as the initial heat sink for any postulated transient or accident condition. Energy is transferred to the pressure suppression pool by either the discharge piping from the reactor pressure safety/relief valves or the Connecting Vent System. The safety/relief valve discharge piping is used as the energy transfer path for any condition which requires the operation of the safety/relief valves. The Connecting Vent System is the energy transfer path for all energy releases to the drywell.

Of all the postulated transient and accident conditions, the instantaneous circumferential rupture of a reactor recirculation pipe represents the most rapid energy addition to the pool. For this accident, the Connecting Vent System, which connects the drywell and suppression chamber, conducts flow from the drywell to the suppression chamber without excessive resistance.

The vent header and downcomers distribute this flow effectively and uniformly in the pool. The pressure suppression pool receives this flow, condenses the steam portion of this flow, and releases the noncondensable gases and any fission products to the pressure suppression chamber air space.

3.1.4 Pressure Suppression Chamber

The pressure suppression chamber is a steel pressure vessel in the shape of a torus encircling the drywell, with a major diameter of approximately 108 ft. and a cross-sectional diameter of 29.5 ft. The pressure suppression chamber contains approximately 105,600 cu ft of water and has a net air space above the water pool of approximately 114,000 cu ft. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the Reactor Building. Space is provided between the concrete in the Reactor Building and the torus for inspection and maintenance.

3.1.5 Pressure Suppression Pool

The pressure suppression pool is approximately 105,600 cu ft. of water contained within the pressure suppression chamber. It serves both as a heat sink for postulated transient and accidents and as a source of water for the Emergency Core Cooling Systems.

The pressure suppression pool receives energy in the form of steam, non-condensables and water from the pressure safety relief system valve discharge piping or the Connecting Vent System downcomers which discharge underwater. The steam is condensed by the pressure suppression pool. The condensed steam and any water carryover cause an increase in pool volume and temperature. Energy can be removed from the pressure suppression pool when the Residual Heat Removal System is operating in the pressure suppression pool cooling mode.

The pressure suppression pool is the primary source of water for the Core Spray and Low Pressure Coolant Injection Systems and the secondary source of water for the Reactor Core Isolation Cooling and High Pressure Coolant Injection Systems. The

water level and temperature of the pressure suppression pool are continuously monitored in the Control Room.

As a result of the Mark I Containment Program, a vent header deflector, saddle plates under the torus, and anchor bolts with tie-down structures permitting the engagement of the concrete base mat with the torus saddles and columns have been installed to provide additional strength to the torus system during the steam quenching mode.

3.1.6 Connecting Vent System

A system of large vent pipes connects the drywell and the pressure suppression chamber. A total of 8 circular vent pipes are provided, each having a diameter of 6.75 ft. The vent pipes are designed for the same pressure and temperature conditions as the drywell and suppression chamber. Jet deflectors are provided in the drywell at the entrance of each vent pipe to prevent possible damage to the vent pipes from jet forces. The vent pipes are provided with expansion joints which are inserted between the vent insert and the vent pipe to accommodate differential motion between the drywell and pressure suppression chamber. The expansion joints are designed to the same requirements as the drywell and pressure suppression chamber.

The vent pipes are connected to a 4 ft-9 inch diameter vent header in the form of a torus which is contained within the air space of the suppression chamber. Projecting downward from the header are 96 downcomer pipes, 24 inch in diameter and terminating approximately 4 ft. below the water surface of the pressure suppression pool (9 feet 7 inches above the bottom of the torus). The vent header has the same temperature and pressure design requirements as the vent pipes. The number and size of the downcomer pipes was selected to conform to the range of parameters examined in the Bodega Bay tests.

During the course of the Mark I Containment short term program, studies of pool swell phenomena showed that a differential pressure between the drywell and torus would significantly reduce the pool swell loads. The drywell-torus differential pressure reduces the length of the water leg inside the downcomer. In the event of a LOCA, the downcomer clearing and subsequent bubble formation will occur earlier at a lower driving pressure.

The differential pressure is being maintained greater than or equal to 1.7 psi at JAF as a one load mitigation technique to restore the intended margins of safety in the containment design. The additional structural assessments required by NUREG 0661 have been made to demonstrate that the containment can maintain its functional capability when the differential pressure control is out of service. Additional limiting conditions for plant operation included in the Technical Specifications are based on the guidance of NUREG 1433. They provide an adequate basis for application of differential pressure control as an effective long term mitigation technique.

The eight bellows type expansion joints in the vent lines between drywell and torus were designed, fabricated, and nondestructively examined in accordance with the ASME

Boiler and Pressure Vessel Code for Nuclear Vessels, Section III, Subsection B, 1968 Edition including the 1968 Summer Addendum, plus Code Cases 1330-1 and 1177-5.

3.1.7 Pipe Penetrations

Four general types of pipe penetrations are provided:

a. Lines connected to the Reactor Coolant System incorporate a sleeve to extend the drywell to the outer isolation valve to contain the effluent in case of a pipe break.

b. Hot lines where the thermal stresses would be too great if directly welded to the drywell incorporate additional design features to mitigate the thermal effects.

c. Small diameter lines (e.g., the CRD and the 1-inch diameter instrument lines) use the penetration design shown in FSAR Figure 5.2-7.

d. Cold lines not connected to the Reactor Coolant System are unsleeved as shown in FSAR Figure 5.2-4.

3.1.8 Electrical Penetrations

The electrical penetrations include electrical power, control, and instrument leads. The penetration sleeve is welded to the primary containment vessel. A bonding resin is utilized in the seals where the cable emerges from the penetration. The penetration is capable of being leak tested outside the drywell. A nitrogen blanket at 15 psig is maintained inside the electrical penetration assemblies to eliminate the accumulation of moisture from air.

3.1.9 TIP Penetrations

Traversing incore probe (TIP) guide tubes pass from the Reactor Building through the primary containment.

3.1.10 Control Rod Drive Penetrations

Control rod drive penetrations are sealed by means of a thick walled sleeve to permit welding into the shell without burn-throughs, cracks, interior granulation and other deleterious effects. Penetration welds on both sides of the shell ensure resistance to moments generated by hydraulic shock. All sleeve to shell welds are stress relieved. Additional hydraulic shock resistance is achieved by the close-fitting mechanical joint between the sleeve and end fitting.

3.1.11 Personnel and Equipment Access Locks

A personnel lock, a personnel escape lock, two equipment hatches and a CRD removal hatch are provided for access to the drywell. The escape lock is mounted concentrically within one of the equipment hatches. All of the above locks and hatches are provided with double gaskets to permit inter- space leak testing.

The doors of the personnel and escape locks are mechanically interlocked to ensure that at least one door is sealed at all times when primary containment is required. The locking mechanisms are designed so that a tight seal is maintained when the doors are subjected to the design pressure.

Drywell entry is limited to conditions where: (1) the reactor power is fifteen percent or less of rated thermal power; (2) administrative or automatic controls shall be in place to assure reactor power remains less than or equal to 15% power during drywell entry, and; (3) no reactor power changes are planned due to control rod position and recirculation pump speed. These restrictions do not preclude inserting control rods to terminate unplanned events such as excessive reactor coolant system heat-up rate.

3.1.12 Access to the Pressure Suppression Chamber
Access to the pressure suppression chamber is provided from the Reactor Building at three locations. There are one 4 ft. diameter and two 2 ft. diameter manhole entrances with testable double gasketed bolted covers connected to the chamber by steel pipes. The access ports are opened only when the reactor is shut down and the Pressure Suppression System is not required to be operational.

3.1.13 Access for Refueling Operations
The drywell vessel head is removed during refueling operations. During normal operation the head is held in place by bolts and is sealed with a testable double-seal arrangement.

3.2 Justification for the Technical Specification Change

3.2.1 Chronology of Testing Requirements of 10 CFR Part 50, Appendix J

The testing requirements of 10 CFR Part 50, Appendix J, provide assurance that leakage from the containment, including systems and components that penetrate the containment, does not exceed the allowable leakage values specified in the TS. Title 10 CFR Part 50, Appendix J also ensures that periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment and the systems and components penetrating primary containment. The limitation on containment leakage provides assurance that the containment would perform its design function following an accident up to and including the plant design basis accident. Appendix J identifies three types of required tests: 1) Type A tests, intended to measure the primary containment overall integrated leakage rate; 2) Type B tests, intended to detect local leaks and to measure leakage across pressure-containing or leakage limiting boundaries (other than valves) for primary containment penetrations, and; 3) Type C tests, intended to measure containment isolation valve leakage rates. Type B and C tests identify the vast majority of potential containment leakage paths. Type A tests identify the overall (integrated) containment leakage rate and serve to ensure continued leakage integrity of the containment structure by evaluating those structural parts of the containment not covered by Type B and C testing.

In 1995, 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," was amended to provide a performance-based Option B for the containment leakage testing requirements. Option B requires that test intervals for Type A, Type B, and Type C testing be determined by using a performance-based approach. Performance-based test intervals are based on consideration of the operating history of the component and resulting risk from its failure. The use of the term "performance-based" in 10 CFR Part 50, Appendix J refers to both the performance history necessary to extend test intervals as well as to the criteria necessary to meet the requirements of Option B.

Also in 1995, RG 1.163 (Reference 1) was issued. The RG endorsed NEI 94-01, Revision 0, (Reference 5) with certain modifications and additions. Option B, in concert with RG 1.163 and NEI 94-01, Revision 0, allows licensees with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the test frequency for the containment Type A (ILRT) test from three tests in 10 years to one test in 10 years. This relaxation was based on an NRC risk assessment contained in NUREG-1493, (Reference 6) and Electric Power Research Institute (EPRI) TR-104285 (Reference 7) both of which showed that the risk increase associated with extending the ILRT surveillance interval was very small. In addition to the 10-year ILRT interval, provisions for extending the test interval an additional 15 months was considered in the establishment of the intervals allowed by RG 1.163 and NEI 94-01, but that this "should be used only in cases where refueling schedules have been changed to accommodate other factors."

In 2008, NEI 94-01, Revision 2-A (Reference 8), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J, subject to the limitations and conditions noted in Section 4.0 of the NRC Safety Evaluation Report (SER) on NEI 94-01. The NRC SER was included in the front matter of this NEI report. Nuclear Energy Institute 94-01, Revision 2-A, includes provisions for extending Type A ILRT intervals to up to 15 years and incorporates the regulatory positions stated in RG 1.163 (September 1995). It delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance testing frequencies. Justification for extending test intervals is based on the performance history and risk insights.

In 2012, NEI 94-01, Revision 3-A (Reference 2), was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J and includes provisions for extending Type A ILRT intervals to up to 15 years. Nuclear Energy Institute 94-01 has been endorsed by RG 1.163 and NRC SERs of June 25, 2008 (Reference 9) and June 8, 2012 (Reference 10) as an acceptable methodology for complying with the provisions of Option B to 10 CFR Part 50. The regulatory positions stated in RG 1.163 as modified by NRC SERs of June 25, 2008 and June 8, 2012 are incorporated in this document. It delineates a performance-based approach for determining Type A, Type

B, and Type C containment leakage rate surveillance testing frequencies. Justification of extending test intervals is based on the performance history and risk insights. Extensions of Type B and Type C test intervals are allowed based upon completion of two consecutive periodic as-found tests where the results of each test are within a licensee's allowable administrative limits. Intervals may be increased from 30 months up to a maximum of 120 months for Type B tests (except for containment airlocks) and up to a maximum of 75 months for Type C tests. If a licensee considers extended test intervals of greater than 60 months for Type B or Type C tested components, the review should include the additional considerations of as-found tests, schedule and review as described in NEI 94-01, Revision 3-A, Section 11.3.2.

The NRC has provided the following concerning the use of grace in the deferral of ILRTs past the 15 year interval in NEI 94-01, Revision 2-A, NRC SER Section 3.1.1.2:

> "As noted above, Section 9.2.3, NEI TR 94-01, Revision 2, states, "Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per 15 years based on acceptable performance history." However, Section 9.1 states that the "required surveillance intervals for recommended Type A testing given in this section may be extended by up to 9 months to accommodate unforeseen emergent conditions but should not be used for routine scheduling and planning purposes." The NRC staff believes that extensions of the performance-based Type A test interval beyond the required 15 years should be infrequent and used only for compelling reasons. Therefore, if a licensee wants to use the provisions of Section 9.1 in TR NEI 94-01, Revision 2, the licensee will have to demonstrate to the NRC staff that an unforeseen emergent condition exists."

NEI 94-01, Revision 3-A, Section 10.1 concerning the use of grace in the deferral of Type B and Type C LLRTs past intervals of up to 120 months for the recommended surveillance frequency for Type B testing and up to 75 months for Type C testing, states:

> "Consistent with standard scheduling practices for Technical Specifications Required Surveillances, intervals of up to 120 months for the recommended surveillance frequency for Type B testing and up to 75 months for Type C testing given in this section may be extended by up to 25% of the test interval, not to exceed nine months.
>
> Notes: For routine scheduling of tests at intervals over 60 months, refer to the additional requirements of Section 11.3.2.
>
> Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions. This provision (nine month extension) does not apply to valves that are restricted and/or limited to 30 month intervals in Section 10.2 (such as BWR MSIVs) or to valves held to the base interval (30 months) due to unsatisfactory LLRT performance."

The NRC has also provided the following concerning the extension of ILRT intervals to 15 years in NEI 94-01, Revision 3-A, NRC SER Section 4.0:

> "The basis for acceptability of extending the ILRT interval out to once per 15 years was the enhanced and robust primary containment inspection program and the local leakage rate testing of penetrations. Most of the primary containment leakage experienced has been attributed to penetration leakage and penetrations are thought to be the most likely location of most containment leakage at any time."

3.2.2 Current JAF Primary Containment Leakage Rate Testing Program Requirements

Title 10 CFR Part 50, Appendix J was revised, effective October 26, 1995, to allow licenses to choose containment leakage testing under either Option A, "Prescriptive Requirements," or Option B, "Performance-Based Requirements." On October 4, 1996 the NRC approved License Amendment No. 234 for JAF (Reference 13) authorizing the implementation of 10 CFR Part 50, Appendix J, Option B for Type A, B and C tests. Current TS 5.5.6 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR Part 50, Appendix J, Option B, as modified by approved exemptions. The program is required to be in accordance with the guidelines contained in RG 1.163. RG 1.163 endorses, with certain exceptions, NEI 94-01, Revision 0, as an acceptable method for complying with the provisions of Appendix J, Option B.

RG 1.163, Section C.1 states that licensees intending to comply with 10 CFR Part 50, Appendix J, Option B, should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 (Reference 5) rather than using test intervals specified in American National Standards Institute (ANSI)/American Nuclear Society (ANS) 56.8-1994. Nuclear Energy Institute 94-01, Section 11.0 refers to Section 9, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per ten years based on acceptable performance history. Acceptable performance history is defined as completion of two consecutive periodic Type A tests where the calculated performance leakage was less than $1.0L_a$ (where L_a is the maximum allowable leakage rate at design pressure). Elapsed time between the first and last tests in a series of consecutive satisfactory tests used to determine performance shall be at least 24 months.

Adoption of the Option B performance based containment leakage rate testing program altered the frequency of measuring primary containment leakage in Types A, B, and C tests but did not alter the basic method by which Appendix J leakage testing is performed. The test frequency is based on an evaluation of the "as found" leakage history to determine a frequency for leakage testing which provides assurance that leakage limits will not be exceeded. The allowed frequency for Type A testing as documented in NEI 94-01 is based, in part, upon a generic evaluation documented in NUREG-1493. The evaluation documented in NUREG-1493 included a study of the dependence or reactor accident risks on containment leak tightness for differing types of containment types, including a Mark I BWR similar to the JAF containment structure.

NUREG-1493 concluded in Section 10.1.2 that reducing the frequency of Type A tests (ILRT) from the original three tests per ten years to one test per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Types B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements. Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, NUREG-1493 concluded that increasing the interval between ILRTs is possible with minimal impact on public risk.

Compliance with 10 CFR Part 50, Appendix J, provides assurance that the primary containment, including those systems and components which penetrate the primary containment, do not exceed the allowable leakage rate specified in the Technical Specifications and Bases. The allowable leakage rate is determined so that the assumed leakage in the safety analysis is not exceeded. For FitzPatrick, a program is established to implement the leakage rate testing of the Primary Containment as required by 10 CFR Part 50.54(o), Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, Performance-Based Containment Leak-Test Program", dated September 1995, as modified by the exception that Type C testing of valves not isolable from the containment free air space may be accomplished by pressurizing in the reverse direction provided that testing in this manner provides equivalent or more conservative results than testing in the accident direction. If potential atmospheric leakage paths (e.g., valve stem packing) are not subjected to test pressure, the portions of the valve not exposed to test pressure shall be subject to leakage rate measurement during regularly scheduled Type A testing. NRC safety evaluation for Technical Specification Amendment 234 (Reference 13) provides justification to perform a soap bubble test for 17 valves with pressurized stem/bonnet boundaries during regularly scheduled Type A testing to provide a direct indication of the leak-tightness of the packing and body-to-bonnet gaskets. The acceptance criterion for this test is zero bubbles. A list of these valves, the leakage rate measurement method, and acceptance criteria are contained in the JAF Containment Leak Rate Test Program.

3.2.3 JAF 10 CFR Part 50, Appendix J, Option B Licensing History

October 4, 1996

The Commission issued Amendment No. 234 to Facility Operating License No. DPR-59 for the James A. FitzPatrick Nuclear Power Plant. The amendment consisted of changes to the Technical Specifications (TSs) in response to the application transmitted by letter dated March 27, 1996, as supplemented April 24, 1996, and August 15, 1996.

The amendment changes permitted the implementation of 10 CFR Part 50, Appendix J, Option B, with an exception to the guidelines of Regulatory Guide 1.163 for Type C testing of primary containment isolation valves in the reverse (non-accident) direction. (Reference 13)

April 14, 2000

The Commission issued Amendment No. 261 to Facility Operating License No. DPR-59 for the James A. FitzPatrick Nuclear Power Plant (JAFNPP). The amendment consisted of changes to the Technical Specifications (TSs) in response to the application transmitted by letter dated February 26, 1998, as supplemented October 14, 1999.

The amendment changed the TS by changing the value of the allowable containment leakage rate to 1.5 percent per day and correcting conflicting information in TS Section 4.6.C, “Coolant Chemistry.” (Reference 15)

August 13, 2002

The Commission issued Amendment No. 275 to Facility Operating License No. DPR-59 for the James A. FitzPatrick Nuclear Power Plant. The amendment consisted of changes to the Technical Specifications in response to the application transmitted by letter dated November 2, 2001, as supplemented by letters dated January 9 and July 10, 2002.

The amendment changed the Current Technical Specifications and the Improved Technical Specifications Main Steam Isolation Valve Leakage Surveillance Requirement along with conforming changes to Bases and the Primary Containment Leakage Rate Testing Program. (Reference 16)

September 28, 2004

The Commission issued Amendment No. 279 to Facility Operating License No. DPR-59 for the James A. FitzPatrick Nuclear Power Plant. The amendment consisted of changes to the Technical Specifications (TSs) in response to the application transmitted by letter dated July 28, 2003, as supplemented on May 20, 2004.

The amendment revised TS 5.5.6, "Primary Containment Leakage Rate Testing Program," to allow a one-time extension of the interval between the Type A, integrated leakage rate tests, from 10 years to no more than 15 years; that is no later than March 7, 2010. (Reference 17)

3.2.4 Integrated Leakage Rate Testing History (ILRT)

As noted previously, JAF TS 5.5.6 currently requires Type A, B, and C testing in accordance with RG 1.163, which endorses the methodology for complying with Option B. Since the adoption of Option B, the performance leakage rates are calculated in accordance with NEI 94-01, Section 9.1.1 for Type A testing. Tables 3.2.4-1 lists the past JAF Type A ILRT results.

Table 3.2.4-1, JAF Type A ILRT History		
Test Date	**As Found Test Results (% Weight per Day)**	**As Left Test Results (% Weight per Day)**
Sep. 1974	0.0767 [1]	0.0767
Nov. 1978	0.336 [1]	0.298
Feb. 1982	0.253658 [1]	0.236958
May 1985	0.281214 [1]	0.239642
Apr. 1987	0.321139 [1]	0.318011
Jun. 1990	0.4035 [1]	0.2704
Mar. 1995	0.31999 [1 2]	0.06299
Oct. 2008	0.8052 [1 3]	0.6045

Note 1: All Type A testing has been performed at test pressures greater than Pa.

Note 2: Data Analysis Technique used – Absolute Method, leakage rates were calculated using Total Time Leakage Per ANSI/ ANS 56.8-1987.

Note 3: Data Analysis Technique used - Absolute Method and the leakage rates were calculated using the Total Time Analysis equations as described in BN-TOP-1.

The Type A test acceptance criteria is as follows in accordance with TS 5.5.6:

a. The peak primary containment internal pressure for the design basis loss of coolant accident, Pa, is 45 psig.

b. The maximum allowable primary containment leakage rate, La, at Pa, shall be 1.5% of containment air weight per day.

c. The leakage rate acceptance criteria are:

   1. Primary containment leakage rate acceptance criteria is ≤ 1.0 La. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 La for the Type B and Type C tests, and ≤ 0.75 La for the Type A tests.

3.2.5 Net Positive Suction Head (NPSH) for ECCS Pumps

Adequate net positive suction head (NPSH) is provided for all ECCS pumps. Adequate NPSH does not depend upon pressurized containment for initial core cooling. The RHR and core spray pumps require less than 2 psig for containment cooling during the long term transient following a LOCA. The only factors considered in calculating NPSH for initial core cooling are the elevation difference between the pump suction centerline and the water surface (positive factors) and vapor pressure of the water and line losses in

the piping (including suction strainers) (negative factors). The current design basis considers the additional head loss across the suction strainers with debris generated and transported to the suppression pool during the most limiting long-term LOCA.

In the original design of the plant, the entire spectrum of possible operating modes of the core standby cooling network (ECCS) were examined for adequacy with regard to NPSH for the HPCI, Core Spray, and RHR pumps. There was sufficient NPSH at all of the pumps at any time since the RHR system limits the suppression pool temperature rise.

As a result of the Power Uprate, Increased Lake Water Temperature, and ECCS Strainer Modifications, additional analyses have been performed for the most limiting operating conditions. The most limiting of all the various modes occurs during the long term transient following a Design Basis Loss-Of-Coolant Accident when one core spray and one RHR pump will be running continuously. JAF FSAR Figures 6.5-1A and 6.5-1B provide plots of the minimum containment pressure required and that which would actually occur in order to demonstrate that adequate NPSH would exist for the RHR and CS pumps, respectively, following a LOCA. Except for the long term transient following a LOCA, pressure in the torus above atmospheric is not required for adequate NPSH.

In order to demonstrate the inherent margin, the following is a list of the major assumptions used to calculate the suppression pool temperature and the minimum containment pressure following the Design Basis Loss of Coolant Accident:

1. Off site power is assumed lost at the time of the accident and is not restored during the period of interest.

2. One of the on site emergency power sources fails and remains out of service during the entire transient.

3. The service water temperature remains at its maximum postulated value of 85°F throughout the transient. (Safety related heat removal requirements of the RHRSW and ESW systems have been evaluated at a lake water temperature of 87°F and 85°F, respectively.

4. The RHR heat exchanger has its design fouling factor.

5. Prior to the accident, the maximum temperature of 150°F exists in the drywell together with 100 percent humidity. Normal operating conditions would be 135 ^{o}F and 20 percent.

6. Initial drywell pressure of 16.65 psia and initial wetwell pressure 14.95 psia.

7. The discharge of the RHR pump is being returned to the system via the drywell and torus sprays, and the containment atmosphere is at the spray temperature; this minimizes the containment pressure.

The result of assumptions 1, 2, 3, and 4 is to maximize the peak suppression pool temperature and minimize the peak pressure. With no off-site power and with one emergency a-c power source out-of-service, the pool will be cooled by one RHR heat exchanger with 100 percent service water flow. This together with the maximum service water temperature (85°F) results in a peak pool temperature of 196.3°F. The suppression pool is assumed to be the only heat sink even though the metal structures within the containment are capable of storing considerable energy. No credit is taken for any heat losses from the containment other than the energy being removed from the RHR heat exchanger.

The NPSH requirements of Safety Guide No. 1 were not strictly conformed to in the original plant design since the equipment and systems were designed and purchased prior to the promulgation of Safety Guide No. 1. The need to credit less than 2 psig containment overpressure for RHR was documented in the original plant Safety Evaluation Report. Containment overpressure of less than 2 psig for Core Spray was approved later in Licensing Amendment No. 239 (Reference 11) for power uprate. The dependence on overpressure was justified by the availability of elevated containment pressure following the event and conservative models used to calculate the available suction heads. However, as a result of updated containment analysis, it is shown that adequate NPSH is available to the ECCS pumps assuming the maximum long-term suppression pool temperature with no increase in containment pressure above that present prior to the postulated LOCA.

3.3 Plant Specific Confirmatory Analysis

3.3.1 Methodology

An evaluation has been performed to assess the risk impact of extending the JAF ILRT intervals from 10 years to 15 years. The purpose of this analysis is to provide an assessment of the risk associated with implementing a permanent extension of the JAF containment Type A ILRT interval from ten years to fifteen years. The risk assessment follows the guidelines from NEI 94-01, Revision 3-A (Reference 2), the methodology used in EPRI TR-104285 (Reference 7), the NEI “Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals” from November 2001 (Reference 21), the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in Regulatory Guide 1.200 (Reference 4) as applied to ILRT interval extensions, risk insights in support of a request for a plant’s licensing basis as outlined in Regulatory Guide (RG) 1.174 (Reference 3), the methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval (Reference 32), and the methodology used in EPRI 1009325, Revision 2-A of EPRI 1018243 (Reference 20).

The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined that for a representative PWR plant (i.e., Surry), that containment isolation failures contribute less than 0.1% to the latent risks from reactor accidents. Consequently, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures for JAF.

NEI 94-01 Revision 2-A contains a Safety Evaluation Report that supports using EPRI Report No. 1009325 Revision 2-A, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," for performing risk impact assessments in support of ILRT extensions (Reference 20). The guidance provided in Appendix H of EPRI Report No. 1009325 Revision 2-A builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

In the SER issued by NRC letter dated June 25, 2008 (Reference 9), the NRC concluded that the methodology in EPRI TR-1009325, Revision 2, was acceptable for referencing by licensees proposing to amend their TS to extend the ILRT surveillance interval to 15 years, subject to the limitations and conditions noted in Section 4.0 of the Safety Evaluation (SE). Table 3.3.1-1 addresses each of the four limitations and conditions for the use of EPRI 1009325, Revision 2.

Table 3.3.1-1, EPRI Report No. 1009325 Revision 2 Limitations and Conditions

Limitation/Condition (From Section 4.2 of SE)	**JAF Response**
1. The licensee submits documentation indicating that the technical adequacy of their PRA is consistent with the requirements of RG 1.200 relevant to the ILRT extension.	JAF PRA technical adequacy is addressed in Section 3.3.2 of this submittal and Attachment 4, "Evaluation of Risk Significance of Permanent ILRT Extension," Appendix A, Attachment 1, which addresses the Technical Adequacy of the PRA modeling.

Table 3.3.1-1, EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**JAF Response**
2.a The licensee submits documentation indicating that the estimated risk increase associated with permanently extending the ILRT surveillance interval to 15 years is small, and consistent with the clarification provided in Section 3.2.4.5 of this SE.	Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 2.17E-8/year using the EPRI guidance; this value increases slightly to 2.20E-8/year if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of Regulatory Guide 1.174. [See Attachment 4]
2.b Specifically, a small increase in population dose should be defined as an increase in population dose of less than or equal to either 1.0 person-rem per year or 1% of the total population dose, whichever is less restrictive.	The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.0087 person-rem/year. EPRI Report No. 1009325, Revision 2-A [Reference 20] states that a very small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. [See Attachment 4]
2.c In addition, a small increase in CCFP should be defined as a value marginally greater than that accepted in a previous one-time 15 year ILRT extension requests. This would require that the increase in CCFP be less than or equal to 1.5 percentage point.	The increase in the conditional containment failure from the 3 in 10-year interval to 1 in 15-year interval is 0.824%. EPRI Report No. 1009325, Revision 2-A states that increases in CCFP of ≤ 1.5% is very small. [See Attachment 4]

Table 3.3.1-1, EPRI Report No. 1009325 Revision 2 Limitations and Conditions	
Limitation/Condition (From Section 4.2 of SE)	**JAF Response**
3. The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation of the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate accident case (accident case 3b) used by the licensees shall be 100 L_a instead of 35 L_a.	The representative containment leakage for Class 3b sequences used by JAF is 100 L_a, based on the recommendations in the latest EPRI report (Reference 20) and as recommended in the NRC SE on this topic (Reference 9). It should be noted that this is more conservative than the earlier previous industry ILRT extension requests, which utilized 35 L_a for the Class 3b sequences. [See Attachment 4]
4. A licensee amendment request (LAR) is required in instances where containment over-pressure is relied upon for emergency core cooling system (ECCS) performance	Adequate NPSH is available to the ECCS pumps assuming the maximum long-term suppression pool temperature with no increase in containment pressure above that present prior to the postulated LOCA. Refer to Section 3.2.5 of this submittal.

3.3.2 Technical Adequacy of the PRA

Technical adequacy of the Probablistic Risk Assessment (PRA), synonymous with Probabilistic Safety Assessment (PSA) is presented in Attachment 4 Appendix A, Attachment 1 of this submittal.

Internal Events PRA Quality Statement for Permanent 15-Year ILRT Extension

The JAF PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause failure events. The PRA model quantification process used for the JAF PRA is based on the event tree and fault tree methodology, which is a well-known methodology in the industry.

Entergy employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating Entergy nuclear power plants. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the JAF PRA model.

PRA Maintenance and Update

The Entergy risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plant. This process is defined in the procedure EN-DC-151, "PSA Maintenance and Update." This procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at all operating Entergy nuclear power plants. In addition, the procedure also defines the process for implementing regularly scheduled and interim PRA model updates, and for

tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience, etc.). To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plant, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model. Potential PRA model changes resulting from these reviews are entered into the Model Change Request (MCR) database, and a determination is made regarding the significance of the change with respect to the current PRA model.
- New engineering calculations and revisions to existing calculations are reviewed for their impact on the PRA model.
- Plant-specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years, and
- Industry standards, experience, and technologies are periodically reviewed to ensure that any changes are appropriately incorporated into the models.

In addition, following each periodic PRA model update, Entergy performs a self-assessment to assure that the PRA quality and expectations for all current applications are met. The Entergy PRA maintenance and update procedure requires updating of all risk informed applications that may have been impacted by the update including but not limited to:

- System/component risk significance rankings
- PRA training materials
- AOV / MOV Risk Rankings
- Online Risk Model (EOOS)
- Mitigating System Performance Index input (MSPI)

BWROG Regulatory Guide 1.200 Peer Review of the JAF PRA Model
The JAF PRA internal events model went through BWROG Regulatory Guide 1.200 peer review in September 2009. The NEI 05-04 process (Reference 18), the American Society of Mechanical Engineers/American Nuclear Society (ASME/ANS) PRA Standard (Reference 30), and Regulatory Guide 1.200, Rev. 2 (Reference 4) were used for the peer review.

The 2009 JAF PRA Peer Review was a full-scope review of all the Technical Elements of the internal events, at-power PRA:

- Initiating Events Analysis (IE)
- Accident Sequence Analysis (AS)
- Success Criteria (SC)
- Systems Analysis (SY)
- Human Reliability Analysis (HR)
- Data Analysis (DA)
- Internal Flooding (IF)

- Quantification (QU)
- LERF Analysis (LE)
- Maintenance and Update Process (MU)

The JAF PRA Peer Review process uses capability categories to assess the relative technical merits and capabilities of each technical supporting requirement reviewed. Three capability category levels are used to indicate the relative quality level of each supporting requirement. Capability category assignments are made based on the judgment of the Peer Review Team after reviewing: (1) the PRA model, (2) the documentation; and, (3) the prior PRA Peer Review results (for historical background).

During the JAF PRA model Peer Review, the technical elements identified above were assessed with respect to Capability Category II criteria to better focus the Supporting Requirement assessments. The ASME/ANS PRA Standard has 326 individual Supporting Requirements; 310 Supporting Requirements are applicable to the JAF PRA model. Sixteen (16) of the ASME/ANS PRA Standard Supporting Requirements are not applicable to JAF (e.g., PWR related, multi-site related). Of the 310 ASME/ANS PRA Standard Supporting Requirements applicable to the JAF PRA model, approximately 94% satisfied Capability Category II criteria or greater. Of the 53 Findings and Observations (F&Os) generated by the Peer Review Team, 24 were considered Findings, 27 were Suggestions, and 2 were Best Practices.

Consistency with Applicable PRA Standards
As a result of the BWROG Regulatory Guide 1.200 peer review, 51 F&Os have been identified for potential improvement to the JAF PRA model. These F&Os are tracked in the Entergy Model Change Request (MCR) database. Of the identified 51 F&Os, 21 were considered not meeting at least the Capability Category II criteria. Attachment 4 of this submittal, Table A-1 summarizes the open F&Os along with an initial assessment of the impact for this application. For each F&O in Table A-1, applicability for this ILRT extension application is evaluated. If an impact is not expected to be negligible, then this assessment may include the performance of additional sensitivity studies or PRA model changes to confirm the impact on the risk analysis and justify why the change does not impact the PRA results used to support the application. Attachment 4 of this submittal, Table A-2 summarizes the closed F&Os and the actions taken to close the F&Os.

External Events PRA Quality Statement for Permanent 15-Year ILRT Extension

External hazards were evaluated in 1996 in the JAF Individual Plant Examination of External Events (IPEEE) submittal in response to the NRC IPEEE Program (Generic Letter 88-20, Supplement 4) (Reference 19). The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks. The results of the JAF IPEEE study are documented in the JAF IPEEE Report (Reference 29). The primary areas of external event evaluation at JAF were internal fire, seismic, high winds, floods, and other external hazards.

Fire Analysis
The JAF IPEEE fire analysis was performed using EPRI's Fire PRA Implementation Guide (Reference 28). The EPRI Fire-Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data (Reference 22).

The fire analysis was revised after the original IPEEE submittal in response to NRC requests for additional information (RAIs) regarding fire-modeling progression, developed during their review of the IPEEE. The updated results are reflected in NUREG-1742, "Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program" (Reference 31) for JAF. In addition, as noted in that NUREG, a number of plant and procedural changes (including strict limitations on storage and use of combustible and flammable material in plant areas) were made as a result of the IPEEE fire analysis. The impact of these enhancements is not reflected in the IPEEE fire results.

Other changes to the plant configuration, procedures and equipment performance have also taken place since completion of the IPEEE. These changes would tend to reduce the overall CDF as well as the fire risk contribution found in the IPEEE. The significant reduction in the internal events CDF since the original JAF IPEEE submittal bears this out. These changes include the following:

- Service, instrument, and breathing air compressors were replaced.
- Operators are directed to maximize CRD flow in certain accident sequences.
- SRV Electric Lift mod to install an SRV alternate actuation system.
- A new procedure (EP-10) directs operators to align the fire protection system to the tube side of the RHR heat exchanger in loss of containment heat removal accident sequences.
- Revised station blackout procedures to explicitly address bus recovery.
- Provision of a back-up battery charger that can be aligned to either station battery.
- Proceduralized RCIC operation without DC power.
- Proceduralized starting EDG without DC power, as well as field flashing without station batteries.

Thus, although the JAF IPEEE fire risk model has not been updated since its original issuance, use of the IPEEE model would tend to give conservative results.

Seismic Analysis
In the IPEEE, JAF performed a Seismic Margin Assessment (SMA), which is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis.

High Winds, Floods, and Other External Hazards (HFO)

In addition to internal fires and seismic events, the JAF IPEEE analysis of HFO external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Since JAF was designed (with construction started) prior to the issuance of the 1975 Standard Review Plan (SRP) criteria, JAF performed a plant hazard and design information review for conformance with the SRP criteria. For HFO events that were not screened out by compliance with the 1975 SRP criteria, additional analyses were performed to determine whether or not the hazard frequency was acceptably low. Based on those analyses, these hazards were determined in the JAF IPEEE to be negligible contributors to overall plant risk.

Technical Adequacy Summary

The technical adequacy of the JAF PRA is consistent with the requirements of Regulatory Guide 1.200 (Reference 4) as is relevant to this ILRT interval extension, as detailed in Attachment 4 of this submittal, Appendix A Attachment 1.

3.3.3 Summary of Plant-Specific Risk Assessment Results

The findings of the JAF Risk Assessment contained in Attachment 4 confirm the general findings of previous studies that the risk impact associated with extending the ILRT interval from three in ten years to one in 15 years is small. The JAF plant-specific results for extending ILRT interval from the current 10 years to 15 years are summarized below:

Based on the results from Attachment 4, Section 5.2, “Analysis”, and the sensitivity calculations presented in Attachment 4, Section 5.3 “Sensitivities”, the following conclusions regarding the assessment of the plant risk associated with permanently extending the Type A ILRT test frequency to fifteen years are:

- Regulatory Guide 1.174 (Reference 3) provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Regulatory Guide 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year and increases in LERF less than 1.0E-07/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 2.17E-8/year using the EPRI guidance; this value increases slightly to 2.20E-8/year if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be “very small” using the acceptance guidelines of Regulatory Guide 1.174.

- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.0087 person-rem/year. EPRI Report No. 1009325, Revision 2-A (Reference 20) states that a very small

population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.

- The increase in the conditional containment failure from the 3 in 10-year interval to 1 in 15-year interval is 0.824%. EPRI Report No. 1009325, Revision 2-A (Reference 20) states that increases in CCFP of ≤ 1.5% is very small. Therefore, this increase is judged to be very small.

- Several sensitivities are performed in Attachment 4, Section 5.3. As shown in Section 5.3.1, when both the internal and external event contributions are combined, the total change in LERF of 2.55E-7 meets the guidance for small change in risk, as it exceeds 1.0E-7/yr and remains less than 1.0E-6 change in LERF and the total LERF is 3.42E-6. Other sensitivities show the baseline ILRT extension analysis (as performed in Attachment 4, Section 5.2) is conservative.

Therefore, increasing the ILRT interval to 15 years is considered to be insignificant since it represents a very small change to the JAF risk profile.

3.3.4 Previous Assessments

The NRC in NUREG-1493 (Reference 6) has previously concluded the following:

- Reducing the frequency of Type A tests (ILRTs) from three per 10 years to one per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B and C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.

- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond one in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test the integrity of the containment structure.

The findings for JAF confirm these general findings on a plant specific basis considering the severe accidents evaluated, the containment failure modes, and the local population surrounding JAF.

Details of the JAF risk assessment are contained in Attachment 4 of this submittal.

3.4 Non-Risk Based Assessment

Consistent with the defense-in-depth philosophy discussed in RG 1.174, JAF has assessed other non-risk based considerations relevant to the proposed amendment. JAF has multiple inspections and testing programs that ensure the containment structure remains capable of meeting its design functions and that are designed to identify any degrading conditions that might affect that capability. These programs are discussed below.

3.4.1 Surveillance Test ST-15B Suppression Chamber and Drywell Deterioration Inspection

The purpose of this inspection is to inspect the accessible surfaces of the primary containment for evidence of structural deterioration, as required by 10CFR50 Appendix J Option B, and the Primary Containment Leakage Rate Testing Program.

Evidence of structural deterioration includes the following:

- Paint scaling, peeling, rusting, or chipping
- Rust stains
- Pitting of surfaces
- Corrosion or cracks
- Loose parts or attachments
- Broken welds
- Delamination

Inspectors shall also be observant of the following:

- Potential defects in the drywell liner that indicate degradation from the reverse side. These indications could include bulging of metal plates, or areas that do not appear to be flat or conforming to the pre-established radius of the liner wall.
- Potential construction and protective coating deficiencies and foreign material in containment.

The areas subject to inspection include the following:

- Accessible interior surfaces of the drywell, including the drywell head.
- Accessible interior surfaces of the torus. If the torus is not drained, only the area above the water line is considered accessible.
- Accessible exterior surfaces of the torus, and exterior surface of drywell head.

If any evidence of structural deterioration is found during performance of this inspection, the evidence is photographed, a work request is initiated to repair, replace, and/or perform an engineering evaluation accepting noted condition.

3.4.2 Primary Containment Coatings Program

The internal surfaces of the drywell and suppression chamber steel were pickled in accordance with the Steel Structures Painting Council System SSPC-SO-8 and shop coated with 4 mils of an inorganic zinc coating. Shop coating was omitted adjacent to areas of field welding. These areas, after welding were cleaned and field coated with 4 mils of an inorganic zinc coating.

Subsequent to the initial shop preparation, the interior carbon steel surfaces of the drywell were cleaned of all deleterious materials and topcoated with a polyamide epoxy coating to a dry thickness of 2 mils. The immersed and non-immersed carbon steel surfaces of the torus interior, vent pipes, and the interior and exterior surfaces of the header and downcomer were cleaned of all deleterious materials and field coated with an inorganic zinc coating to achieve a total dry film thickness of 4.5 to 9.0 mils.

All coatings used inside primary containment are qualified for JAF specific normal and design basis accident environmental conditions in accordance with ANSI N5.12-1974 and ANSI N101.2-1972.

The following procedures are among the containment coating controls identified in the response to NRC Generic Letter 98-04 (Reference 14):

- ST-15B, Suppression Chamber and Drywell Deterioration Inspection
- IS-M-01, Preparation and Painting of Plant Structures, Components and Concrete Items

Coatings assessments are completed each refueling outage in accordance with Surveillance Test ST-15B. Coatings assessments have also been performed in accordance with the drywell preservation and torus preservation programs and concluded that both the drywell and the torus are in good condition.

3.4.3 Containment Inservice Inspection Program

The Code of Record for the First Ten-Year Interval, 1st Period, IWE Containment Inspection Program was the 1992 Edition of ASME B&PV Code Section XI, Inspection Program B, as required by the 1996 amendments to 10CFR50.55a.

The Code of Record for the First Ten-Year Interval, 2nd Period, IWE Containment Inspection Program was the 1998 Edition of ASME B&PV Code Section XI, Inspection Program B, with Repair/Replacement performed in accordance with 1992 Edition of ASME B&PV Code Section.

The Second Ten-Year Interval for IWE containment inspections at JAF commences on March 1, 2007 coincident with the start of the 4th 10-Year ISI Program Interval.

The 2001 Edition of ASME B&PV Code Section XI, with the 2003 Addenda, is the

Code of Record for the Second Ten-Year IWE Containment Inspection Program Interval.

The IWE Containment Inspection Program was established in response to growing concerns related to containment degradation, and increasing concerns related to ineffectiveness of engineering walk downs prior to 10 CFR 50 Appendix J tests. For these reasons the Nuclear Regulatory Commission published an amendment to the Code of Federal Regulation, 10 CFR 50.55a.

The amendment to 10 CFR 50.55a requires that the utility implements an addition to its existing Inservice Inspection Program, to develop a Containment Inspection Program, that meets the requirements of the American Society of Mechanical Engineers Boiler and pressure Vessel Code, Section XI, Subsection IWE, 1992 Edition, with 1992 Addenda and as supplemented by 10 CFR 50.55a. The utility was required to develop the program and complete the first period inspections by September 9, 2001. The first period examinations were completed as scheduled meeting the requirements as described.

The Nuclear Regulatory Commission, in NRC letter, TAC NO MB2946, dated 5/1/2002, granted Relief Request - 27 to implement the Containment Inspection Program that meets the requirements of the ASME Section XI, Subsection IWE, 1998 Edition, '98 Addenda as supplemented by 10CFR50.55a and additional guidelines delineated in the NRC letter. The inspections of the First Ten-Year Containment Inservice Inspection Interval Program for the Primary Containment pressure boundary components of both the Drywell and Torus and integral attachments and, the Vent System although not part of the Primary Containment pressure boundary were developed after giving due consideration to the limitations of design, geometry and materials of construction.

Inspection Periods

The First Containment Inservice Inspection Interval was divided into three successive inspection periods as determined by calendar years of plant service within the inspection interval. Identified below are the period dates for the First Containment Inservice Inspection Interval. The First Containment Inservice Inspection Interval as defined by Table IWE-2412-1, Inspection Program "B", coincided with the Third Inservice Inspection Interval; see Table IWB-2412-1, Inspection Program "B", except for the start date of the First & Second Periods.

The First IWE Inspection Interval and Periods along with the 2nd and 3rd Inspection Intervals and Periods are shown in Table 3.4.3-1.

Table 3.4.3-1, JAF Containment Inservice Inspection Periods

Inspection Periods	Period Start Dated	Period End Dates
1st Interval Period 1	September 28, 1997	March 27, 2001 (RO13 & RO14)
1st Interval Period 2	March 28, 2001	November 30, 2004 (RO15 & RO16)

Table 3.4.3-1, JAF Containment Inservice Inspection Periods		
Inspection Periods	**Period Start Dated**	**Period End Dates**
1st Interval Period 3	December 1, 2004	February 28, 2007 (RO-17)
2nd Interval Period 1	March 1, 2007	December 31, 2010 (RO18 & RO19)
2nd Interval Period 2	January 1, 2011	December 31, 2013 (RO20)
2nd Interval Period 3	January 1, 2014	December 31, 2016 (RO21 & RO22)
3rd Interval Period 1	January 1, 2017	December 31, 2019 (RO23)
3rd Interval Period 2	January 1, 2020	December 31, 2023 (RO24 & RO25)
3rd Interval Period 3	January 1, 2024	December 31, 2026 (RO26 & RO27)

Note: If the Second and/or Third Periods require an adjustment, IWA-2430 allows the inspection interval to be reduced or extended by as much as one year to enable an inspection to coincide with a plant outage.

Note: The dates for the 3rd Interval are proposed dates. The 3rd Interval Plan has not been issued at this time.

Subsection IWE Code Examination Category E-C Augmented Examinations

Examination Category E-A, Containment Surfaces, Item Number E4.11, Visible Surfaces, and E4.12, Surface Area Grid Minimum Wall Thickness Location, fall under this category.

Components Subject to Examination (IWE-1210)

Components subject to examination are Class MC pressure retaining components and their integral attachments and to metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments. These examinations shall apply to surface areas, including welds and base metal.

Components Exempted from Examination (IWE-1220)

Components (or parts of components) exempted from the examination requirements of IWE- 2000 are as follows:

- Vessels, parts, and appurtenances outside the boundaries of the containment system as defined in the Design Specifications;
- Embedded or inaccessible portions of containment vessels, parts, and appurtenances that met the requirements of the original Construction Code.

- Portions of containment vessels, parts, and appurtenances that become embedded or inaccessible as a result of vessel repair /replacement activities if the conditions of IWE- 1232(a) and (b) and IWE-5220 are met;
- Piping, pumps, and valves that are part of the containment system, or which penetrate or are attached to the containment vessel. These components shall be examined in accordance with the requirements of IWB or IWC, as appropriate to the classification defined by the Design Specifications.

<u>Inaccessible Inspection Areas (IWE-1232)</u>

In accordance with IWE-1231, a minimum of 80% of the surface area defined in Table IWE-2500-1, Examination Category E-A, and areas defined in IWE-1240 are required to remain accessible for inspection.

Accessible surface areas are those areas of the containment pressure retaining surface or integral attachments with visual access by line of sight with adequate lighting from permanent vantage points, not obstructed by permanent plant structures, equipment, or components.

The following areas of the primary containment pressure boundary and integral attachments are inaccessible for IWE inspection:

Drywell

- Drywell Skirt (Welded Integral Attachment): The Drywell was erected upon a steel skirt to facilitate activities during construction. Following completion of the construction activities the Drywell skirt was totally encased in concrete as part of the foundation for the Drywell.

- Drywell Construction Manway-16X-3 (Welded Integral Attachment): A 24" diameter Construction Manway was installed in the bottom of the Drywell to facilitate construction work on the inside of the Drywell. Following completion of the construction activities, the Construction Manway was seal welded closed and completely encased in concrete as part of the Drywell foundation.

- Drywell Shell Plates (Outside Surface): Following erection and testing of the Drywell structure, a concrete foundation was poured to Elevation 256'-6". In addition, a (two-foot-thick) shield wall, with a 2" air gap to the Drywell shell plates, was poured up to Elevation 345'-8 3/4".

- Drywell Shell Plates (Inside Surface): Following erection and testing of the Drywell structure, a concrete floor was poured to Elevation 256'-6"(Approx. surface area of liner plate 1770 sq. ft.). This area although inaccessible is exempt from IWE Inspection as per IWE-1220.

- Drywell Cooling Ductwork: The Drywell Cooling Return Ductwork is fabricated using the Drywell liner plate as part of the actual ductwork structure. The

ductwork circles the Drywell and extends from EL. 300'-10" to 295'-7"(Approx. surface area of the liner plate 924 sq.ft.)

In addition, to protect the area adjacent to the 4 Main Steam Lines, 4 missile shields are mounted on the inside surface of the Drywell shell plates at Elevations approx. 334'-0" to 342'-8" (Approx. surface area of liner plate 60 sq. ft./per location, total 240 sq. ft.).

There are also 153-12" diameter weld pads (Approx. surface area of liner plate, total 120.2 sq. ft.) welded to the inside surface of the Drywell.

- Drywell Penetration (Welded Integral Attachment): The extensions (Cold Penetrations - 3" nominal pipe diameter and less) of all the as-welded penetrations that project through the Drywell shell can not be inspected. Various penetrations (Hot Penetrations, Electrical Penetrations, Airlocks and Hatches) that extend through the Drywell external shield wall can be partially inspected outside the shield wall.

- Drywell Female Stabilizer (Welded Integral Attachment): The female stabilizer which is located at Elevation 330'-11 3/4",on the outside surface (between the Drywell outside surface and the Drywell external shield wall) of the male stabilizer can not be inspected without disassembling the 23 1/2" OD Manway.

Vent System

- Bellows Assembly: The eight, 93" OD stainless steel bellows (approx. surface area of plate, 520 sq. ft.) can not be inspected without removing their protective metal shields. The location and weight of the protective metal shields, makes the possibility of damaging the bellows relatively high, if removal is required.

Suppression Chamber (Torus)

- Suppression Chamber Shell Plates (Inside Surface): There are 32-12" diameter weld pads (Approx. surface area of liner plate, total 25.1 sq. ft.) welded to the inside surface of the suppression chamber.

<u>Calculation of Accessible Area (Inside Surface Examination)</u>

IWE-1230 defines the minimum requirements for accessibility for examination from at least one side of the vessel.

The total surface area that is inaccessible amounts to an area of 1829.1 sq. ft. (inside surface examination). The total interior surface of the primary containment (with the Torus drained) amounts to approximately 64,500 sq. ft. as per CB&I Document, Drywell and Suppression Chamber Cleaning and Painting Instructions. Therefore, approximately 97% of the total inside surface area is accessible for examination.

Augmented Examinations other than those required by IWE-1241

Augmented Containment Inspection Program for Examinations Other Than Those Required By IWE-1241

Examinations previously performed from the Torus exterior shell at designated HPCI and RCIC locations are no longer performed based on Root Cause Analysis Report CR-JAF-2005-2593 Rev.2; CA-18 & 19 along with CR-JAF-2007-2149 CA-1.

Ultrasonic thickness measurements shall be performed from the exterior surface of the Torus Shell in accordance with JAF calculation JAF-CALC-05-00037 Rev. 0, Assessment of 2004 R16 Torus UT Inspection Data. These examinations are being performed in support of the Torus Preservation Program and are not required based on the IWE Containment Inspection Program.

Acceptability of Inaccessible Areas

For Class MC applications, JAF shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. For each inaccessible area identified, JAF shall provide the following in the Owners Activity Report-1, as required by 10 CFR 50.55a(b)(2)(ix)(A):

- A description of the type and estimated extent of degradation, and the conditions that led to the degradation;
- An evaluation of each area, and the result of the evaluation, and;
- A description of necessary corrective actions.

JAF has not needed to implement any new technologies to perform inspections of any inaccessible areas at this time. However, Entergy Operations, Inc. (Entergy) actively participates in various nuclear utility owners groups and ASME Code committees to maintain cognizance of ongoing developments within the nuclear industry. Industry operating experience is also continuously reviewed to determine its applicability to JAF. Adjustments to inspection plans and availability of new, commercially available technologies for the examination of the inaccessible areas of the containment would be explored and considered as part of these activities.

3.4.4 Supplemental Inspection Requirements

With the implementation of the proposed change, TS 5.5.6 will be revised by replacing the reference to RG 1.163 (Reference 1) with reference to NEI 94-01, Revision 3-A (Reference 2). This will require that a general visual examination of accessible interior and exterior surfaces of the containment for structural deterioration that may affect the containment leak-tight integrity be conducted. This inspection must be conducted prior to each Type A test and during at least three other outages before the next Type A test

if the interval for the Type A test has been extended to 15 years in accordance with the following sections of NEI 94-01, Revision 3-A:

- Section 9.2.1, "Pretest Inspection and Test Methodology"
- Section 9.2.3.2, "Supplemental Inspection Requirements"

In addition to the IWE examinations scheduled in accordance with the Containment Inservice Inspection Program, the performance of inspections utilizing ST-15B, "Suppression Chamber and Drywell Deterioration Inspection", will be utilized to ensure compliance with the visual inspection requirements of TS SR 3.6.1.1.1, and NEI 94-01 Revision 3-A. The inspections utilizing ST-15B are performed each refueling outage.

3.4.5 Primary Containment Leakage Rate Testing Program - Type B and Type C Testing Program

JAF Types B and C testing program requires testing of electrical penetrations, airlocks, hatches, flanges, and containment isolation valves in accordance with 10 CFR Part 50, Appendix J, Option B, and RG 1.163. The results of the test program are used to demonstrate that proper maintenance and repairs are made on these components throughout their service life. The Types B and C testing program provides a means to protect the health and safety of plant personnel and the public by maintaining leakage from these components below appropriate limits. In accordance with TS 5.5.6, the allowable maximum pathway total Types B and C leakage is 0.6 L_a where L_a equals 320 SLM. In addition to the TS Limit, an outage performance limit of 160 SLM, or 0.5 L_a is imposed by the Program.

As discussed in NUREG-1493 (Reference 6), Type B and Type C tests can identify the vast majority of all potential containment leakage paths. Type B and Type C testing will continue to provide a high degree of assurance that containment integrity is maintained.

Table 3.4.5-1 provides local leak rate test (LLRT) data trend summaries for JAF since 2004.

This summary demonstrates a history of satisfactory Type B and Type C tested component performance from the Fall of 2004 through the Fall of 2014 inclusive of the ILRT performed in 2008.

Table 3.4.5-1, JAF Type B and C LLRT Combined As-Found/As-Left Trend Summary

RFO	2004 RO16	2006 RO17	2008 RO18	2010 RO19	2012 RO20	2014 RO21
AF Min Path (SLM)	99.52	43.15	77.642	65.21	298.104	160.958

Table 3.4.5-1, JAF Type B and C LLRT Combined As-Found/As-Left Trend Summary						
RFO	**2004 RO16**	**2006 RO17**	**2008 RO18**	**2010 RO19**	**2012 RO20**	**2014 RO21**
Fraction of L_a	0.311	0.135	0.243	0.204	0.9315	0.503
AL Max Path (SLM)	45.859	72.393	101.118	74.958	137.481	131.145
Fraction of L_a	0.143	0.226	0.316	0.234	0.430	0.410
AL Min Path (SLM)	34.722	45.399	66.344	50.984	74.88	80.713
Fraction of L_a	0.1085	0.142	0.207	0.159	0.234	0.252

Type B and Type C Local Leak Rate Testing Program Implementation Review

The single valve administrative limit for valve Type C testing is 16 SLM. Tables 3.4.5-2 and 3.4.5-3 identify the components that have not demonstrated acceptable performance during the previous two outages for JAF:

Table 3.4.5-2, JAF Type B and C LLRT Program Implementation Review						
2012-RO20						
Component	**As-Found (SLM)**	**Level 2 Limit (SLM)**	**As-Left SLM**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval (Months)**
02-2RWR-13A	22.1	1.2	0.979	Seat leakage (1)	Piston replaced	24
23MOV-15	22.9	4.2	22.9	Not Identified. (2)	Evaluated as acceptable. (2)	24
27AOV-114	164	6.4	0.144	Disk through the seat. (3)	Disc was realigned and a new T-ring was installed.	30

Table 3.4.5-2, JAF Type B and C LLRT Program Implementation Review						
2012-RO20						
Component	**As-Found (SLM)**	**Level 2 Limit (SLM)**	**As-Left SLM**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval (Months)**
34FWS-28B	61.1	2.6	1.41	Misalignment of the disk to the seat.	The disk and hinge arm were replaced. (4)	24
12MOV-15	26.5	3.2	26.5	Boundary valve leakage. (5)	Evaluated as acceptable. (5)	30
27AOV-132A	(6)	1.6	4.8	(6)	(6)	24
27AOV-101A	138	5.9	1.234	Seat leakage.	(7)	24

1. During performance of ST-39B-X31AC, "Type C Leak Test of RWR A Mini Purge Line Valves", 02-2RWR-13A RWR Pump A Seal Purge Supply Check Valve, failed Level 2 acceptance criteria. Leakage acceptance criteria less than or equal to 1.2 SLM, as found leakage was 22.1 SLM. Deficiency identified as valve piston pitting.

2. During performance of ST-39B-X11, 23MOV-15 failed to meet Level 2 Acceptance Criteria of 4.2 SLM, with a measured leakage of 22.9 SLM. A repair is not required. While the valve did not meet the administrative limit of 16 SLM, the leakage can be accepted on the basis that max path will be under 192 SLM prior to start up as required by Tech Specs.

3. During performance of ST-39B-X26A/B, 27AOV-113 and 27AOV-114 failed Level 2 acceptance criteria having a leak rate of 164 SLM. The vent paths from the original LLRT identified 27AOV-114 as being the valve contributing to the leakage. Task 1 of WO 317275 adjusted the stops on 27AOV-114 with no significant increase in leak rate. Task 11 of the WO removed the spool piece and found the disc to be through its seat, along with a gouge on the spool flange. The disc was realigned and a new T-ring was installed. An informational leakage test with a test flange showed decreased leakage. Upon reassembly, the flange bolting was incrementally torqued until flange leakage was zero (final torque value of 575 ft/lbs). Task 9 of the WO was for a contingency LLRT (ST-39B-X26A/B), resulting as satisfactory with a leak rate of 0.144 SLM, well below the Level 2 acceptance criteria of 6.4 SLM and the administrative limit of 16 SLM.

4. During performance of ST-39B-X9A/B, 34FWS-28B failed Level 2 acceptance criteria of 2.6 SLM. The leakage was measured at 61.1 SLM. Troubleshooting performed indicated no bubbles noted on the refuel floor (indicating the boundary

valve was not leaking) and air was confirmed to be blowing out of the vent path, indicating leakage was by 34FWS-28B. 34FWS-28B was repaired per WO 244983. The disk post to hinge arm interface was worn causing misalignment of the disk to the seat. The disk and hinge arm were replaced. The valve was then again leak rate tested per ST-39B-X9A/B with satisfactory results of 1.41 SLM.

5. During performance of ST-39B-X14, 12MOV-15 failed Level 2 acceptance criteria of 3.2 SLM. The Leakage was measured at 26.5 SLM. The administrative limit for 12MOV-15 is 16 SLM. It was identified that the inboard boundary valve was leaking, evident by bubbles on the refuel floor. Since this valve tested above this value, this test is considered a failure to the Appendix J Containment Leak Rate Program, and testing frequency must be changed from extended frequency per 10 CFR 50 Appendix J Option B to the base interval of 30 months. 26.5 SLM is 23.3 SLM higher than the 3.2 SLM Level 2 limit. An additional 23.3 SLM represents 7.28% of the total allowable leak rate of 320 SLM. It also represents 12.1% of the B and C total of 192 SLM. No repair to this valve is necessary, the measured leakage rate is acceptable.

6. During performance of ST-39B-X220, 27AOV-132A could not be brought to test pressure. As-found minimum pathway leakage was 0.122 SLM. The repair of 27AOV-132A was performed using work order 329274-01. The valve was found closed with no closed indication. Troubleshooting was performed and found 27AOV-132A stroking full stroke but the closed switch not making up. Found bench set at 12 to 30 psig. Lubricated packing, stroked valve several times and adjusted bench set higher to give more seat load (15 to 32 psig). The valve was stroked, full stroke obtained and the closed limit switch adjusted. The valve then stroked and indicated properly. Local Leak Rate Testing (LLRT) was performed Sat.

7. During performance of ST-39B-X202B/G, 27AOV-101A failed Level 2 acceptance criteria with a leak rate of 138 SLM. Maximum allowable is less than or equal to 5.9 SLM. As-found minimum pathway leakage was 70.685 SLM. The adjusting of stops of 27AOV-101A and cleaning the seat of 27VB-6 did not produce satisfactory results. No visible leakage through 27VB-6 indicated the leakage was through the seat of 27AOV-101A. A potential actuator issue was identified via an engineering fleet call. The actuator was disengaged and the manual operator engaged. Manually closing the valve resulted in significant decreased leakage. The air operator was then loosened to allow a strain on the spring can and tightening of the operator mounting bolts. The air actuator was then reengaged and ST-39B-X202B/G was run. This test produced a satisfactory leakage rate of 1.234 SLM, well below the Level 2 acceptance criteria of 5.9 SLM and the administrative limit of 16 SLM.

Table 3.4.5-3, JAF Type B and C LLRT Program Implementation Review

2014-RO21						
Component	**As-Found SLM**	**Level 2 Limit SLM**	**As-Left SLM**	**Cause of Failure**	**Corrective Action**	**Scheduled Interval**
29AOV-86C	103	5.422	0.295	Seat leakage. (1)	Valve seat repaired.	30
02-2RWR-13A	58.9	1.2	7.6	Seat leakage. (2)	(2)	24
23MOV-15	20.86	4.2	9.69	Not Identified. (3)	Evaluated as acceptable. (3)	24
20AOV-95	42.2	2.3	0.074	Seat leakage.	Replaced ball and seal. (4)	30
27AOV-113	(5)	6.4	0.078	Seat leakage.	(5)	30

1. During performance of ST-39B-X7C, 29AOV-86C failed LLRT with a leakage rate of 103 SLM. The As-Found Acceptance Criteria for TS SR 3.6.1.3.10 (21.689 SLM) and Appendix J (320 SLM) testing are based on minimum pathway leakage. Based on a review of LLRT and Appendix J test results (as documented in ST-39B), the minimum pathway leakage limits for both TS SR 3.6.1.3.10 and Appendix J were met. As-found minimum pathway leakage was 0.295 SLM. WO 392549-01 repaired seat leakage on 29AOV-86C. Installed guide pads. The LLRT testing of the valve was effective as total leakage for the "C" line was measured at 0.22 SLM (25 psig).

2. During performance of ST-39B-X31AC, 02-2RWR-13A failed LLRT. Allowable leak rate is <1.2SLM and actual was 58.9SLM. 02-2RWR-40A was closed as part of troubleshooting which allowed the line to pressurize and leakage dropped to 0 SLM which confirmed 02-2RWR-13A was actually leaking by. WO # 389948-01 was completed satisfactory that lapped the new piston to the body seat, installed a new spring as well as a new bonnet. Subsequent leak testing per WO# 389948-02 was satisfactory (7.6 SLM leakage); the testing did not meet Level 2 criteria and is documented under CR-JAF-2014-5239 (Level 2 LLRT roll up CR-JAF-2014-4811). No further corrective actions are needed. Discussion with the LLRT engineer concluded that no more adjustments or corrective actions are needed for the valve in order to be under the total maximum path LLRT value limit of 192 SLM.

   Action Plan Action for 02-2RWR-13A: Initiate/Scope a contingency WO package

to cut out/replace check valve 02-2RWR-13A in next refueling outage (RO22).

3. During performance of ST-39B-X11, 23MOV-15 failed Level 2 acceptance criteria at 20.86 SLM. Acceptance criteria is 4.2 SLM. This valve was later tested and leakage rate was 9.69 SLM. 9.69 SLM is 5.49 SLM over the Level 2 acceptance criteria of 4.2 SLM. The Containment Leakage Rate Program Administrative limit for this valve is 16 SLM. A repair is not required; the measured As-left leakage rate is acceptable.

4. During performance of ST-39B-X19, 20AOV-95 leak test from the pipe tunnel completed unsat due to a leakage of 42.2 SLM. Leakage must be less than or equal to 2.3 SLM. WO 394757 was completed which fixed the valve. Gouges were found in the ball. Ball and seal were replaced. As Left LLRT was 0.074 SLM.

5. During performance of ST-39B-X26A/B, 27AOV-113 and 27AOV-114 failed Level 2 acceptance criteria with gross leakage indicated. WR#00349803 written. WO 393157 was completed; 27AOV-113 valve disc was found approximately 2" open causing the gross leakage rate failure. The valve was repaired (27AOV-114 was removed to facilitate repair). Initial trouble shooting adjusted the stops on 27AOV-113 and a "sweet spot" could not be obtained to allow for a valid As-Found LLRT test. This line is 24" and a 2" opening for a butterfly valve provided a leak path larger than the LLRT test panel could overcome. The work was completed, LLRT was completed and results for as left were acceptable, 0.078 SLM.

3.4.6 License Renewal Report on Containment Leak Rate Program

Summary of Technical Information in the Application
LRA Section B.1.8 describes the existing Containment Leak Rate Program as consistent with GALL AMP XI.S4, "10 CFR 50, Appendix J."

Containment leak rate tests are required for assurance that (a) leakage through primary reactor containment and systems and components penetrating the primary containment does not exceed allowable technical specifications or their bases and (b) there is periodic surveillance of reactor containment penetrations and isolation valves so that proper maintenance and repairs are made during the service life of the containment and systems and components penetrating the primary containment.

Staff Evaluation
During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff interviewed the applicant's technical personnel and reviewed the Containment Leak Rate Program bases documents. Specifically, the staff reviewed the program elements and corresponding bases documents for consistency with GALL AMP XI.S4. The staff noted that the applicant chose 10 CFR Part 50, Appendix J, Option B (performance-based approach) for implementing this program.

The containment leak rate tests are in accordance with the guidance of Regulatory Guide (RG) 1.163 and NEI 94-01. The staff finds the applicant's Containment Leak Rate Program acceptable consistent with GALL AMP XI.S4, including the operating experience attribute, and acceptable.

Operating Experience
LRA Section B.1.8 stated that during the 1995 integrated leakage testing of the primary containment as-found and as-left test data met all applicable test acceptance criteria with no degradation threatening the structural integrity of the containment, indicating the program's effective management of the effects of loss of material and cracking on primary containment components. A QA audit in March 2002 and self-assessments in 2004 and 2005 revealed no issues or findings with impact on program effectiveness. As stated in GALL Report Section XI.S4, "To date, the 10 CFR Part 50, Appendix J, LRT program has been effective in preventing unacceptable leakage through the containment pressure boundary. Implementation of Option B for testing frequency must be consistent with plant-specific operating experience." The program is consistent with the GALL Report and 10 CFR Part 50, Appendix J requirements and, therefore, effective at managing loss of material and cracking on primary containment components.

The staff reviewed the operating experience in the LRA and operating experience reports and also interviewed the applicant's technical personnel and confirmed that plant-specific operating experience showed no aging effects for systems and components within the scope of this program not bounded by industry operating experience. The staff noted there were no aging-related condition reports (CRs) of degradation that would threaten the structural integrity of the containment. The staff found this fact an acceptable indication that components have experienced no aging effects not bounded by industry operating experience.

The staff confirmed that the "operating experience" program element satisfied the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff found this program element acceptable.

UFSAR Supplement
In LRA Section A.2.1.8, the applicant provided the UFSAR supplement for the Containment Leak Rate Program. The staff determined that the information in the UFSAR supplement provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion
On the basis of its audit and review of the applicant's Containment Leak Rate Program, the staff found all program elements consistent with the GALL Report. The staff concluded that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The

staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.5 Operating Experience

During the conduct of the various examinations and tests conducted in support of the Containment related programs previously mentioned, issues that do not meet established criteria or that provide indication of degradation, are identified, placed into the site's corrective action program, and corrective actions are planned and performed.

For the JAF Primary Containment, the following site specific and related industry events have been evaluated for impact on the JAF Primary containment:

- FitzPatrick Licensee Event Report LER-05-003, Plant Shutdown Due to Through-Wall Crack in Torus.
- Generic Letter 87-05, Potential Degradation of Mark I Drywells due to Water Leakage.
- NRC Information Notice 92-20, Inadequate Local Leak Rate Testing.
- NRC Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident because of Construction and Protective Coating Deficiencies and Foreign Material in Containment.
- NRC Information Notice 04-09, Corrosion of Steel Containment and Containment Liner.
- NRC Information Notice 2014-07, Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner.
- FitzPatrick Licensee Event Report LER-2010-004-00, Main Steam Isolation Valve Leak Rate Exceeds Authorized Limit.

Each of these areas is discussed in detail in Sections 3.5.1 through 3.5.7, respectively.

3.5.1 FitzPatrick Licensee Event Report LER-05-003

On June 27, 2005, while the plant was operating at 100 percent power, inspectors discovered a small leak (1-2 drops/minute) through the Torus shell. A subsequent engineering evaluation determined that the Primary Containment was inoperable, the plant was shutdown in accordance with normal shutdown procedures. The declaration of containment inoperability resulted in entering the site emergency plan and declaring an Unusual Event (UE).

The plant's High Pressure Coolant Injection (HPCI) exhaust line, although consistent with original GE design specifications, did not include a HPCI turbine exhaust line sparger. A properly designed sparger was expected to reduce local Torus shell stresses resulting from HPCI turbine exhaust pressure pulses. The plant did not install a HPCI sparger due to inadequate information transfer to JAF from General Electric (GE)

and other nuclear facilities regarding concerns with pressure instability and vibration inside the Torus.

As a result of this design deficiency, the Torus shell experienced localized stress, high cycle fatigue due to rapid condensation of the HPCI exhaust steam at the ring girder weld heat affected zone, resulting in a Torus shell through-wall crack.

As part of the corrective actions, an ASME Code repair was performed to repair the Torus shell. In addition, the HPCI exhaust line and ring girder gusset attachment were modified as required to reduce the associated stresses.

There were no actual safety consequences associated with this event.

Cause of the Event

JAF's original HPCI exhaust line design, although consistent with the original GE design specifications, did not include a HPCI turbine exhaust line sparger. A properly designed and installed condensing sparger is expected to reduce the Torus shell stresses resulting from HPCI turbine exhaust pressure pulses (condensation oscillation).

As a result of this design deficiency, the Torus shell experienced localized stress, high cycle fatigue due to rapid condensation of the HPCI exhaust steam (condensation oscillation) at the ring girder weld heat affected zone, resulting in a Torus shell through-wall crack.

JAF did not install a HPCI sparger due to inadequate information transfer from General Electric (GE) and other nuclear facilities regarding concerns with pressure instability and vibration inside the Torus. Correspondence exists showing that GE was aware of concerns with this pressure instability and Torus vibration as early as 1972. This correspondence discussed the addition of HPCI turbine exhaust line spargers. Since 1972, ten of thirteen stations having Mark I containments and HPCI systems have installed condensing spargers on the HPCI turbine exhaust pipe. A review of related plant documentation (correspondence, reports and calculations) did not identify any information that would have prompted action to add a condensing sparger prior to or following initial plant operation. This inadequate information transfer was due to a lack of formally in sharing operating experience prior to the advent of GE Service Information Letters (SILs).

Analysis of the Event

There were no immediate nuclear, radiological or personnel safety issues associated with this event. The plant was shutdown in accordance with normal shutdown procedures and the cracked area of the Torus shell was removed and the Torus shell was repaired in accordance with the applicable ASME codes.

The suppression chamber (Torus) is a steel pressure vessel (Primary Containment Pressure Boundary) in the shape of a Torus encircling the drywell, with a major diameter of approximately 108 feet and a cross-sectional diameter of 29 feet 6 inches. The Torus shell is stiffened by 16 internal ring girders located at the miter joints. The Torus is supported by 16 pairs of reinforced columns at the ring girder locations.

It is estimated that the Torus crack propagated through-wall during the most recent operation of the HPCI system (surveillance test) on May 16, 2005, as no Torus shell leakage was observed during a semi-annual contamination survey performed on April 19, 2005.

The following specific scenarios were considered to determine the safety significance of the identified condition:

Large Break LOCA (LBA)
Due to the rapid depressurization from the Design Basis Event, the HPCI system essentially does not operate, which means that the Torus shell local stresses at the crack location would not be increased by the HPCI exhaust induced condensation oscillation. There would be increased blowdown loads through the drywell to torus downcomers due to the higher pressures assumed in the LBA. The resultant Torus shell loads have been previously evaluated under the Mark I containment program. The Torus shell crack is calculated to grow but still remain stable and below the critical crack length. The critical crack length is the point at which point stable crack growth accelerates and becomes unstable. In addition, the resultant crack growth is less than that of the IBA. Consequently, the leakage rate from the resultant crack would be bounded by the leakage rate in the IBA.

Intermediate Break LOCA (IBA)
The Intermediate Break LOCA assumes 8 hours of HPCI operation and 45 psig containment pressure. In this scenario, HPCI is the primary source of makeup water to the reactor vessel. The Torus shell crack was calculated to grow but still remain stable and below the critical crack length. The resultant Torus shell crack corresponds to a leakage rate much less than 1 gallon per minute (approximately 0.5 gpm).

Small Break LOCA (SBA)
The small break LOCA also assumes 8 hours of HPCI operation but containment pressure is less than that assumed for the IBA. As such, the loads through the downcomers are smaller which results in lower overall stresses on the Torus shell crack area. Consequently, the Torus shell crack is calculated to grow less and the resultant leakage is bounded by the IBA case.

Station Blackout (SBO)
A station blackout (SBO) accident is one in which all normal (offsite) and emergency (onsite) AC power is lost. Such an accident renders balance of plant systems, containment heat removal systems, and most emergency core cooling systems

and other make-up systems inoperable. In an SBO, emergency core cooling systems are therefore limited to steam-driven, de-powered, or manually operated systems. These systems include RCIC, HPCI, the safety relief valves (SRVs)/automatic depressurization system (ADS), and the diesel-engine-driven fire pumps. The SBO analysis assumes 4 hour coping time duration. Consequently, the crack growth associated with the SBO event is bounded by the IBA.

<u>Anticipated Transient Without Scram (ATWS)</u>
An ATWS event occurs when an anticipated transient is followed by a failure of the reactor protection system to scram the reactor. As a result, plant operators must achieve reactor subcriticality by controlling reactor power, pressure, and level. Containment overpressurization must also be prevented in ATWS events involving MSIV isolation.

The most challenging scenario would be an ATWS event with MSIV closure. This will cause rapid pressurization inside the reactor vessel as the core continues to generate steam at near-rated conditions. This pressure increase causes the SRVs to lift and a recirculation pump trip when reactor pressure reaches 1153 psig. The recirculation pumps will also trip when the decreasing water level reaches 105.4 inches above the top of active fuel (TAF). These two actions reduce reactor pressure by decreasing reactor power to 40 percent (as a result of reduced core inlet flow caused by the recirculation pump trip) and by venting steam to the Torus through the SRVs.

The MSIV closure interrupts steam supply to the feed pump turbines. This leads to continued core steaming and loss of core liquid level. When the reactor water level falls below 126.5 inches above TAF, HPCI and RCIC are initiated. The estimated duration of this ATWS sequence would be 4 hours. The reduced operating time and higher Torus water temperatures would result in a smaller crack size and leakage rate than for the IBA.

<u>Plant Transients</u>
Using the duration from the August 2003 loss of grid event, HPCI was in operation for a total of approximately 14.5 hours. This equates to approximately 434,000 condensation oscillation cycles. With extended HPCI operation beyond the first several hours, reactor pressure decreases and pool temperature rises. As reactor pressure decreases, the HPCI turbine mass flow rates and exhaust pressures decrease and Torus water temperatures increase. With HPCI loading at these lower pressures, the crack growth and resultant leakage rate are bounded by the IBA scenario.

<u>Flooding Considerations</u>
The potential for piping system failures to impact other equipment due to flooding was considered in Appendix H of JAF's Individual Plant Examination (IPE). The level of concern is when the level reaches the RHR and Core Spray pump motors for each Crescent area (5 feet). The corresponding volume for the West Crescent area is 56,100 gallons and for the East Crescent area is 100,980 gallons. Assuming no water is retained in the Torus room and no credit is given for pumping water from the area, it

would take a 3.6 gpm leakage rate to reach this level in 30 days. As the worst case leakage is less than one gpm, there will be no adverse effects related to flooding.

For the transient case, flooding would be annunciated using level switches in the crescent areas. The floor drain sump pumps are rated at 100 gpm, but the ability to process water in the Radwaste system is limited by the floor drain filtration skid. The existing filtration skid has a maximum capacity of 40 gpm. In order to overcome the current system water processing capabilities, the leak would have to exceed 40 gpm. As the worst case leakage (IBA) was calculated to be less than one gpm, there is no flooding concern.

Conclusion

Based on the lab analysis of the Torus shell crack area and fracture mechanics evaluation, the Torus shell crack was calculated to grow in a stable fashion and remain below the critical crack length limit for all postulated cases. The resultant leakage for the bounding IBA case was determined to be less than one gpm. This relatively low leakage rate corresponds to onsite and offsite radiological conditions that are well within limits. In addition, there is ample makeup water supply to the Torus in excess of 1 gpm. Consequently, the safety significance of this event was minimal.

Extent of Condition

As part of the extent of condition review of the through-wall crack in the Torus shell, a visual inspection of the remaining structural supports in the Torus was performed. No other leakage was identified during this examination. In addition, Non-Destructive Examination (NOE), using Magnetic Particle Testing (MT) and Ultrasonic Testing (UT) techniques, was performed in the areas where the HPCI and RCIC turbine exhaust lines discharge into the Torus. No additional indications of cracking were identified. A thorough evaluation of all Torus penetrations and associated piping was performed. The results of the review indicated that no additional Torus shell flaws could have occurred.

After the ASME code repair was performed on the Torus shell, the entire primary containment (drywell, torus and connecting vents) was pressurized to the containment peak calculated pressure of 45 psig. During this pressure test, all the accessible portions of the containment were subjected to a general visual examination. No defects in the repair weld area were detected nor was any leakage in the primary containment identified.

Corrective Actions

- Completed an ASME code repair of the Torus crack.
- Completed a Root Cause Analysis (RCA) for this event.
- Generated a Repetitive Task item to perform accelerated NDE on the high stress areas of the Torus shell in the vicinity of the HPCI turbine exhaust line and the RCIC turbine exhaust line, subsequent to turbine operation.

- Modified the HPCI turbine exhaust line and ring girder gusset attachment as required to reduce the stresses on the Torus shell due to condensation oscillation.
- The HPCI exhaust discharge to the Suppression Pool was modified to incorporate the use of a sparger.

3.5.2 Generic Letter 87-05. Request for Additional Information - Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells

Generic Letter 87-05 described Drywell shell degradation, which occurred at Oyster Creek Nuclear Generating Station as a result of water intrusion into the air gap between the outer Drywell surface and the surrounding concrete and subsequent wetting of the sand cushion at the bottom of the air gap. The initial response to this generic letter for JAF was provided in a letter to the NRC (Reference 12).

The cause of this degradation was determined to be from water entering the drywell air gap region, and becoming trapped in the sand cushion region at the base of the air gap. The air gap region surrounds the outside surface of the drywell and extends from the sand cushion region at the bottom, to just below the drywell bellows region at the top. During refueling activities, a potential leakage path could exist through the drywell bellows region, as experienced on the reported Mark I containment.

In response to the request, JAF reviewed the design for the sand cushion and the refueling bellows drain systems. The results of this review indicated that the sand cushion is covered with stainless steel plates with an adhesive seal to prevent in leakage. Drains are provided above these plates and also at the bottom of the sand cushion. Because of this design arrangement, no ultrasonic thickness measurements were required for the drywell shell plates adjacent to the sand cushion.

To ensure the drywell shell exterior remains dry during refueling evolutions, the drywell to reactor building bellows assembly separates the refueling cavity filled with water from the exterior surface of the drywell shell. Any leakage through the bellows assembly is directed to a drain system (inner bellows to the Drywell Equipment Drain Sump, outer bellows to the Condensate Storage Tanks), where two lines are each equipped with a flow indicator/switch that will alarm in the Control Room in the event of a bellows failure. A Preventive Maintenance Test of 19FIS-61 is performed to verify the indicator/switch is functional and the Control Room annunciator responds when water is added to the line. In addition, a Preventive Maintenance - Functional Test of 19FIS-62 is performed to verify the indicator/switch and associated Control Room annunciator are functional.

Operating Experience:

In response to NRC Generic Letter 87-05, the eight sand cushion drain lines were inspected in 1988. Five of the six outer bellows seal drain lines were also inspected.

These inspections were to ensure that the drain lines were unplugged and operational as designed.

Of the eight sand cushion drain lines inspected, six were found to be functional and two were found to be inoperable. Of the two drain lines that were found to be inoperable, one was returned to operability. Stone and Webster Engineering Corporation has stated that both the as found and as left conditions of the sand cushion drain lines is sufficient to fulfill their design function.

Five of the six bellows seal drain lines were inspected and found to be functional. One of these drain lines, 19-4"-W19-151-61D, was found to contain a foam blockage, which may have caused an impairment of the drain's function in the case of a bellows seal leakage. This foam blockage was removed to provide for optimum flow in the drain line. All five drain lines inspected were vacuumed to further ensure their operability. As the five bellows seal drain lines inspected are operable as designed, and due to their redundant arrangement, no further measures were taken for the uninspected line.

A boroscopic inspection was performed of the sand cushion and air gap drains for the drywell shell during April 2007. The following discrepant conditions were identified:

- Gaps between the metal containment and steel plate located at the top of the sand cushion,
- A tear in the tape between the steel plate and the drywell shell in the air gap,
- Corrosion on the interior of the drain piping and corrosion stains on the exterior surface of concrete wall inside the Torus Room,
- Debris in the sand cushion drain piping and filters, and
- One (1) 100% concrete plugged air gap drain.

Note that these conditions (with the exception of the corrosion stains on the exterior surface of concrete) were previously identified in a memorandum dated November 8, 1988 that summarized the results of a 1988 boroscopic inspection of the same areas.

Engineering Response:

1. Based on review of the recent boroscopic video of the air gap drains, there were small gapped areas between the drywell shell and the stainless steel plate that lies on top of the sand cushion. A gap approximately 1/8” in width and 4” in length, and exists in the southeast quadrant air gap drain location. There is also an open area in the southwest quadrant where the adhesive seal is partially damaged and the opening is very small. The adhesive seal (tape) is to cover the gap area between the drywell shell and the stainless steel plate, when the plate was placed into position above the sand cushion area. The adhesive seal acts as a flexible joint due to thermal growth (of the drywell shell) between the surface of the drywell shell and the stainless steel plate. The stainless steel plate was added above the sand cushion to help keep any water from entering the

sand cushion from the air gap area. The area around the exterior of the drywell shell, between the stainless steel cover plate and the drywell shell exterior surface, is dry and shows no signs of moisture or past accumulation of water. The minimal gapped areas do not impact the overall intended function of the drains to allow any water from accumulating in the air gap and sand cushion areas.

2. The damaged adhesive seal in the southwest air gap drain was identified during the initial 1988 boroscope inspection that was performed for the sand cushion and refuel bellows drain lines. Memo dated November 8, 1988, stated that the damage will have little impact on the operability of the drain, as the opening that has been created by the tear in the adhesive seal between the stainless steel plate and the drywell shell is very small. The length of the tear in the adhesive seal was characterized as very small compared to the overall circumference of the entire sealed area.

   The torn adhesive seal was viewed again during the 2007 boroscopic inspection of the air gap and sand cushion drain lines. The inspection of the drains revealed no evidence of water within the air gap or the sand cushion area. There were no signs of corrosion or degradation to the drywell shell surface in the area of the drains. The small area of damaged adhesive seal (tape) in the southwest air gap drain has not detached and does not block the end of the air gap drain. The air gap and sand cushion drains can still function as intended, i.e., water is able to flow through the drain lines with no major obstructions. The area around the adhesive seal (tape) and in all the air gap and sand cushion drains is dry and shows no signs of moisture or accumulation of water.

3. Based on the review of the recent boroscopic video of the air gap and sand cushion drains, there are areas inside the drain piping for all eight (8) lines that show signs of minor surface corrosion. There were no signs of deep corrosive pitting inside the eight (8) drain lines. There are traces of staining and residue remaining on the concrete wall surface. The stains are located at approximately Elevation 251’-0”. The rust color staining is directly below the opening for the sand cushion drain lines located in the southeast, southwest and northwest quadrants. The concrete surface area directly below the air gap drain lines show signs of minor limestone and/or calcium deposits. The stains and concrete residue may be from when the drains were cleaned out in 1988 where drilling (roto-rootering) was used to clean the drains of dirt, concrete and other debris. The stains could also have originated from plant construction of the concrete structure built around the Torus and Reactor shell. While the concrete structure was being constructed, the Torus and Reactor shell were open to the environment (rain and snow), allowing water to drain through the sand cushion and air gap drain lines.

4. There is very little debris remaining inside the air gap drain piping. The debris in the sand cushion drain lines is dry and appears to be concrete dust and particles left from the mechanical pipe cleaning (roto-rooter) process, which was performed in 1988 to clear the drains of obstructions, minor amount of rust particles, and traces of sand particles. The 2007 boroscopic exams revealed no evidence of water within the sand cushion drain piping or in the filter (screen) area. The four (4) sand cushion drain lines are located below the base or bottom of the sand cushion, such that the top side of the filter (screen) is open to the sand cushion. The filter (screen) is clear on the top side in all four (4) sand cushion drains. Thus, water is able to drain down through the sand, into the filter (screen), and exit out through the 2-inch drain line.

If any evidence of moisture is identified JAF will determine additional inspection activities, as appropriate.

JAF monitors refueling bellows leakage drain lines during refueling outages.

3.5.3 NRC Information Notice 92-20, Inadequate Local Leak Rate Testing

NRC Information Notice 92-20 was issued to alert licensees to problems with local leak rate testing of containment penetrations at some plants. Specifically, local leak rate testing could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem.

There is only a single category of primary containment bellows at JAF:

- Top and Bottom Bellows on the eight 6.75 ft. diameter Vent Lines between the Drywell and the Torus.

The bellows listed above are testable 2-ply stainless steel bellows and are tested in accordance with 10 CFR 50, Appendix J, Option B, Type B testing. Until Option B was adopted, Type B testing was performed every two years. Since that time, the test frequency has been extended to once every 120 months. A review of LLRT test records since 1994 when the bellows were first tested has revealed no failures of the bellows leakage tests. The LLRT performance evaluation of the Vent line bellows is summarized in the following table:

Table 3.5.3-1, Vent Line Bellows Performance Summary

Penetration	Last Test Date	Type B Combined Leak Rate (SLM)	Level 2 Limit (SLM) [1]	Type B LLRT Frequency
X-201A	09/25/12	0.035	0.039	120 Month

Table 3.5.3-1, Vent Line Bellows Performance Summary				
Penetration	**Last Test Date**	**Type B Combined Leak Rate (SLM)**	**Level 2 Limit (SLM) [1]**	**Type B LLRT Frequency**
X-201B	09/21/10	0.009	0.039	120 Month
X-201C	09/25/12	0.035	0.039	120 Month
X-201D	09/25/12	0.031	0.039	120 Month
X-201E	09/21/10	0.004	0.039	120 Month
X-201F	09/25/12	0.028	0.039	120 Month
X-201G	09/21/10	0.004	0.039	120 Month
X-201H	09/25/12	0.023	0.039	120 Month

Note 1: The administrative limit is 0.039 SLM or 39 sccm.

Due to the design of the vent pipe expansion bellows, in order for containment atmosphere to leak through these bellows to the reactor building atmosphere, it would have to pass through both plies of the bellows, which would necessitate a double failure to occur. These bellows are essentially static devices in that they are designed for thermal expansion between the drywell and torus during a design-basis accident, and, therefore, have not experienced the inservice stresses that would propagate transgranular stress corrosion cracking. Based on the design, service conditions and current testing applied to these expansion bellows, additional testing or inspection is not warranted.

3.5.4 NRC Generic Letter 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident because of Construction and Protective Coating Deficiencies and Foreign Material in Containment.

The U.S. Nuclear Regulatory Commission (NRC) issued this generic letter for several reasons. It alerted addressees that foreign material continued to be found inside operating nuclear power plant containments. During a design basis loss-of-coolant accident (DB LOCA), this foreign material could block an emergency core cooling system (ECCS) or safety-related containment spray system (CSS) flow path or damage ECCS or safety-related CSS equipment. In addition, construction deficiencies and problems with the material condition of ECCS systems, structures, and components (SSCs) inside the containment continued to be found. Design deficiencies also had been found which could degrade the ECCS or safety-related CSS. No action or information was requested regarding these issues. The NRC had issued many previous generic communications on this subject, as discussed later in this generic letter, and assumes that addressees have had adequate prior notice to consider possible actions at their facilities to address these concerns.

> The NRC also issued this generic letter to alert the addressees to the problems associated with the material condition of Service Level 1 (see definitions of Service Levels in Attachment 3) protective coatings inside the containment and to request information under 10 CFR 50.54(f) to evaluate the addressees' programs for ensuring that Service Level 1 protective coatings inside containment do not detach from their substrate during a DB LOCA and interfere with the operation of the ECCS and the safety-related CSS. The NRC intended to use this information to assess whether current regulatory requirements were being correctly implemented and whether they should be revised.

The internal surfaces of the drywell and suppress ion chamber steel were pickled in accordance with the Steel Structures Painting Council System SSPC-SO-8 and shop coated with 4 mils of an inorganic zinc coating. Shop coating was omitted adjacent to areas of field welding. These areas, after welding were cleaned and field coated with 4 mils of an inorganic zinc coating.

Subsequent to the initial shop preparation, the interior carbon steel surfaces of the drywell were cleaned of all deleterious materials and topcoated with a polyamide epoxy coating to a dry thickness of 2 mils. The immersed and non-immersed carbon steel surfaces of the torus interior, vent pipes, and the interior and exterior surfaces of the header and downcomer were cleaned of all deleterious materials and field coated with an inorganic zinc coating to achieve a total dry film thickness of 4.5 to 9.0 mils.

All coatings used inside primary containment are qualified for JAF specific normal and design basis accident environmental conditions in accordance with ANSI N5.12-1974 and ANSI N101.2-1972.

As localized areas of degraded coatings are identified through the condition assessment / inspection plan, those areas are evaluated and, as necessary, scheduled for repair / replacement. These condition assessments, as well as the resulting repair / replacement activities, assure that the amount of Service Level 1 coatings which may be susceptible to detachment from the substrate during a DBA LOCA event are minimized.

Coatings assessments are performed each refueling outage in accordance with ST-15B, Suppression Chamber and Drywell Deterioration Inspection, and work orders are initiated for any area having coating failures (peeling, flaking, blistering, cracking, or mechanically induced failure such as scraping). Coatings assessments have also been performed in accordance with the drywell preservation and torus preservation programs and concluded that both the drywell and the torus are in good condition. The torus and drywell are visually inspected each outage. To date, no evidence of significant coatings degradation has been identified.

3.5.5 NRC Information Notice 04-09, Corrosion of Steel Containment and Containment Liner (04/27/2004)

The U.S. Nuclear Regulatory Commission (NRC) issued this information notice to alert addressees to recent occurrences of corrosion in freestanding metallic containments and in liner plates of reinforced and pre-stressed concrete containments. It was expected that recipients will review this information for applicability to their facilities and consider actions, as appropriate. However, the suggestions in this information notice were not NRC requirements; therefore, no specific action or written response was required.

Background:
As discussed in Information Notice 97-10, "Liner Plate Corrosion in Concrete Containments," the containment liners have safety factors well above the theoretically calculated strains. Any corrosion (metal thinning) of the liner plate or freestanding metallic containment could change the failure threshold of the containment under a challenging environmental or accident condition. Thinning changes the geometry of the containment shell or liner plate, which may reduce the design margin of safety against postulated accident and environmental loads. Recent experience has shown that the integrity of the moisture barrier seal at the floor-to-liner or floor-to-containment junction is important in avoiding conditions favorable to corrosion and thinning of the containment liner plate material.

Description of Circumstances:
Inspections of containment at the floor level, as well as at higher elevations, have identified various degrees of corrosion and containment plate thinning.

A general visual inspection of Class MC pressure retaining components is performed at JAF and the results are documented. The inspections are performed to identify signs of degradation due to environmental conditions and aging that may affect structural integrity or leak tightness, and to identify the required repairs and/or replacement activities to minimize degradation.

RO15 (2002) IWE Inspections:
Performed UT thickness examinations on Torus locations previously identified as having pitting during a 1996 IWE exam. No readings were found below the calculated minimum wall thickness.

Also, a general visual inspection of the accessible surfaces of the Drywell (interior of the Primary Containment) is performed to examine coatings, the moisture barrier at the concrete-to-Drywell shell plates interface, and an overall condition of the structural integrity of the interior Primary Containment steel and concrete surfaces. Minor discoloration and small areas of coating damage from apparent activities performed in the past were observed. These imperfections do not affect the integrity of the containment and are considered acceptable. All bolted connections were observed to be intact and free of unacceptable discontinuities. This examination includes the

containment dome. Engineering evaluations were not required from the general visual inspections performed during RO15.

3.5.6 NRC Information Notice 2014-07, Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner

Leak-chase channel systems were not installed at JAF, therefore this operating experience is not applicable to the plant or the JAF ISI program.

3.5.7 FitzPatrick Licensee Event Report LER-2010-004-00

On September 17, 2010, following Local Leak Rate Testing (LLRT) of valves 29AOV-80C (Inboard) and 29AOV-86C (Outboard) Main Steam Isolation Valves (MSIVs), it was determined that the allowable leak rate was exceeded for 29AOV-86C. Due to the initial test being performed between the valves (reverse flow for 29AOV-80C), follow-up testing from above the valve plug was conducted on September 21, 2010, at which time 29AOV-80C was also determined to have failed the leak rate test. At the time of testing, the Mode Switch was in Refuel and the plant was conducting Refueling Outage 19.

The excessive leakage on 29AOV-80C, was attributed to corrosion products found on the valve seat during inspection of the valve internals. Leakage on 29AOV-86C was attributed to flow erosion in the stellite seat between the 3 o'clock and 5 o'clock position, causing the disc to be off center and slightly off the seat.

The valves were repaired and tested satisfactorily prior to plant startup, and an Apparent Cause Evaluation was completed.

Background:

The normal sequence of testing for the MSIVs is:

1) Test between the valves at 25 psig per the TS requirement. Check MSL vents to determine which valve is leaking.
2) After Main Steam Line Plugs are installed, test the valves individually from the refuel floor through the test connection on the Main Steam Line Plug at 45 psig.
3) After leakage rates are measured, determine As-Found (AF) minimum pathway to verify whether or not the TS limit of 46 scfh is met.
4) After repairs, if required, leakage rates are measured to determine the As-Left (AL) maximum pathway to verify that the TS limit of 46 scfh is met.

As-Found Leak Rate Test Results:

Minimum Pathway Analysis of "C" Main Steam Line at 45 psig

Inboard	Would not hold pressure
Outboard	Would not hold pressure
Penetration	Would not hold pressure

Event Analysis:

This report was submitted in accordance with 10 CFR 50.73(a)(2)(i)(B), "Any operation or condition which was prohibited by the plant's Technical Specifications," 10 CFR 50.73(a)(2)(ii)(A), "Any event or condition that resulted in the nuclear power plant, including its principal safety barriers, being seriously degraded," and in accordance with 10 CFR 50.73(a)(2)(v), "Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to (C) Control the release of radioactive material."

The primary Containment System has the capability to limit leakage, during any of the postulated design basis accidents for which it is assumed to be functional, such that offsite doses do not exceed the guideline values set forth in 10 CFR 100. Compliance with 10 CFR 50, Appendix J provides assurance that the Primary Containment including those systems which penetrate the Primary Containment do not exceed the allowable leakage rate specified in the TS.

Based on the LLRT failures, 29AOV-80C and 29AOV-86C were disassembled and inspected. The inspection of 29AOV-80C did not identify any indications of seat wear or damage. The presence of corrosion products on the seat was noted. Inspection of 29AOV-86C revealed a small wear mark described as erosion between the three o'clock and five o'clock position in the stellite seat and wear in the bore which would cause the valve disc to be off center and slightly off the seat. These material conditions were the result of normal wear on these components.

Cause of Event:

The LLRT failure of 29AOV-80C was caused by corrosion products fouling the valve seat and the LLRT failure of 29AOV-86C was the result of flow erosion on the valve body and seating surface.

Extent of Condition:

All MSIVs are leak rate tested, as described above, during each refueling outage. No other MSIVs were determined to exceed the Technical Specification Leak Rate Limits and all Maximum Path As-Left leak rates were within the Technical Specification limits.

As-Left Maximum Pathway Leak Rate Analysis of "C" MSL

Inboard	0.215
Outboard	0.215
Penetration	0.215

Assessment of Safety Consequences:

An upper bound on the leak rate through 29AOV-80C and 29AOV-86C could not be determined; therefore, the potential dose consequences of this event could not be precisely quantified. A Level 2 Probabilistic Risk Assessment to estimate the incremental large early release frequency (LERF) increase was conducted to quantify / evaluate the safety significance of this event. The average maintenance model was modified by setting basic events associated with MSIVs 29AOV-80C and 29AOV-86C to TRUE. Specifically, basic events MSV-AOV-OO-80C and MSV-AOV-OO-86C (fails-to-close NO-FO) are changed. These basic events only appear in the primary containment isolation fault tree model as part of the LERF model. Hence, these events have no impact on the core damage frequency.

In addition to changing basic events MSV-AOV-OO-80C and MSV-AOV-OO-86C failure rate; the primary containment isolation system fault tree was modified to reflect that MSIVs failure to close on demand are applicable to plant events that result in core damage at high Reactor Pressure Vessel pressure.

Using the analysis described above results the estimated frequency of a large early release was 2.85×10^{-7} / yr. This frequency is less than the LERF safety goal of 1×10^{-6} /yr. This value represents a 9.2 percent increase from the 'base case' value of 2.61×10^{-7} /yr.

The impact on the LERF as described in Reg. Guide 1.174 defines very small changes in risk as resulting in increases of core damage frequency (CDF) below 10^{-6} /yr and increases in LERF below 10^{-7} /yr. Since the MSIVs leakage does not impact CDF, the relevant metric is LERF. Calculating the increase in LERF is simply the increase in risk from the above LERF base case to the MSIV leakage case or

$$\begin{aligned}\Delta\text{LERF} &= \text{LERF MSIV CASE - LERF BASE CASE}\\ &= 2.85 \times 10^{-7}\text{ /yr} - 2.61 \times 10^{-7}\text{ /yr}\\ \Delta\text{LERF} &= 2.40 \times 10^{-8}\text{ /yr}\end{aligned}$$

Since guidance in Reg. Guide 1.174 defines very small changes in LERF as below 10^{-7} /yr, excessive MSIVs leakage from 29AOV-80C and 29AOV-86C is non-risk significant.

3.5.8 Primary Containment IWE Operating Experience Since Completion of Last ILRT in 2008

<u>RO19 (2010) Inspections</u>

Primary Containment IWE General Examination, Torus Saddle Support

CR-JAF-2010-00895 - IWE General Visual examination of the primary containment (Torus) saddle support assembly identified hold down brackets with relevant conditions per the ASME Section XI program.

Engineering evaluated the condition and accepted as is. EC 0000021438 evaluated the base tie-down bracket gaps that were identified in this condition report that did not meet the requirements provided on the plant drawings. The EC evaluation clarified and added gap tolerances on plant drawings 3.72-16 and 3.72- 17. These drawing changes are attached to the EC as drawing markups.

Primary Containment IWE General Examination, Primary Containment Moisture Barrier Area

CR-JAF-2010-05936 - During scheduled IWE inspection of drywell 256' elevation, degraded conditions at the carbon steel drywell liner interface were recorded per the ASME Section XI program. Primary Containment Liner corrosion identified in CR-JAF-2008-03508 could not be adequately addressed under WO 00166758. The work order was written to determine the extent of corrosion and subsequent repairs of areas identified in the IWE examinations performed in R18 and discussed in CR-JAF-2008-03508.

These conditions were evaluated and acceptable to Engineering for continued service. Work Order 00166758 was revised to perform additional concrete excavation and the surface area was cleaned and prepped for a VT-1 of the steel liner. Pit depth measurements and UT examination of the steel liner was performed. Examinations were accepted based on pitting not exceeding engineering acceptance criteria.

Primary Containment IWE General Examination, Torus Interior

CR-JAF-2010-06235 - ISI VT-1 examination of the Torus wetted surface areas identified delaminated coatings from the 2006 repaired areas at ring girders 15 and 16.

As identified in the condition report, Underwater Construction Company (UCC) divers removed the delaminated /loose coatings during the examination. The coatings removed were essentially the entire coating applied during the 2006 repairs and consisted of an approximate 10" round area. Surface condition of the repaired areas were found in good condition and no FME concerns exists. Work order 00254828 generated to recoat the repair areas during future torus work.

<u>RO20 (2012) Inspections</u>

Primary Containment IWE General Examination, DW 256' - 268'; IWE General / Detailed Examination, DW Liner Interface 256'

CR-JAF-2012-06616 - During scheduled IWE inspection of Primary Containment drywell elevation 256' to 268', General Paint degradation and corrosion / pitting conditions at the drywell liner to floor interface were recorded per the ASME Section XI program.

These conditions were evaluated and acceptable by Engineering for continued service. General paint degradation was acceptable as is: Re-examination of drywell liner to floor interface corrosion/ pitting accepted based on pit depth measurements {less than 10% wall thickness). SIPD JAF-971 is in place for Drywell Liner to floor interface repair and installation of seal. Drywell liner to floor interface corrosion/ pitting continues to be monitored.

Primary Containment IWE General Examination, DW 268' - 292'

CR-JAF-2012-06562 - ASME Section XI, IWE, General Visual examination of the containment surfaces identified coating deficiencies exceeding procedure screening criteria. Coating (paint) was either missing or had minor degradation in various locations.

Engineering evaluated the condition and accepted as is (no significant material loss identified).

Primary Containment IWE General Examination, DW 324' - 340'

CR-JAF-2012-06361 - ASME Section XI, IWE, General Visual examination of the containment surfaces identified coating deficiencies exceeding procedure screening criteria. Coating (paint) was either missing or had minor degradation in various locations.

Engineering reviewed the condition and accepted as is (no material loss identified).

Primary Containment IWE General Examination Torus Interior RB 227' to 272'.

CR-JAF-2012-07201 - ASME Section XI, IWE, General Visual examination of the torus interior surfaces identified coating deficiencies exceeding procedure screening criteria. Coating (paint) degradation and minor corrosion identified in various locations.

Engineering evaluated the condition and accepted as is (no material loss identified).

RO-21 (2014) Inspections

Primary Containment IWE General Examinations were not required in 2014. However, a very detailed Drywell and Torus Inspection was performed per ST-15B "Suppression Chamber and Drywell Deterioration Inspections".

Drywell El. 256' to 268':

Two pits were discovered during RO 20 and documented via CR-JAF-2012-06616. The pits were in the drywell liner plate, near the concrete floor at El. 256'. One pit was 9/64" deep and the other pit was 5/64" deep. The pits were evaluated as sat for continued operation per Engineering Evaluation. The pits did not exceed 10% of the allowable design wall thickness.

Minor lifting of epoxy topcoat adjacent to 29-R1F-HS-120, the MST Snubber. This is consistent with the minor corrosion observed at the drywell to concrete interface at El. 256'.

There are five locations in the order of 2 to 9 square inches below pipe support PFSK-2620. This is loss of topcoat and the primer remains in-tact. This observation is consistent with the minor coating degradation reported in RO 20 and documented in CR-JAF-2012-06558 and CR-JAF- 2012-06562 and evaluated as acceptable for continued operation per an Engineering Evaluation.

Drywell El. 268' to 324':

Minor degradation of the primary containment interior and exterior wall liner and concrete. Reported as "accept as-is" during RFO 20. Reference CR-JAF-2012-06558 and CR-JAF-2012-06562 and evaluated as acceptable for continued operation per Engineering Evaluation.

Coating patch area noted during walk down. This area was on the interior of the steel liner adjacent to the equipment hatch. Patched areas are grey, whereas the topcoat is off-white. No structural implications as this appears to be an area of coating repair.

Torus Interior Inspection:

BAY 1 (B): The primer coating of CZ-11 applied lo the Ring Header, Torus interior above the water line is good. Small area approximately 6" x 5' -0" shows surface rust bleeding through the primer coat of CZ-11 on the top face of the Ring Header. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Down comer on outside wall has minor surface rust at two locations, one is approximately 6" x 3'-0" and the second is about 6" x 5'-0"

BAY 2 (C): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Structural steel stiffener plate between Bays 1 & 2 and the inner wall of the Torus has an area 6" x 2' -0" with surface rust bleeding through the primer coat of CZ-11. 12" diameter pipe near outer wall shows surface rust from water line downward. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Surface rust at junction of ring headed to exterior wall of torus. The corrosion area is estimated at six square feet. Minor surface rust discovered on the ring girder next to the inner wall about 2 feet above the water level. The surface rust is approximately 3" x 2' - 0".

BAY 3 (D): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. 12" diameter pipe near outer wall has surface rust where the pipe is welded to the top part of the Torus. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces.

BAY 4 (E): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Top face of the Ring Header at the junction with the down comer, surface rust bleeding through the CZ-11 primer coat, approximately 3 square feet (6" x 6'). Surface rust on the top face of the 4" pipe line above the Ring Header. The rust area on the line is approximately 2" x 4'-0". At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces.

BAY 5 (F): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Horizontal support between the structural stiffener plate between Bays 5 & 6, surface rust and minor cracking in the primer coat. Surface rust on one of the structural plates (fin) around the Ring Header at the connection to the down comer. The area is approximately 6" x 2' -0". Two 5" diameter plug plates (approx. ½ " thick) have minor surface rust around them. Surface rust approximately 2" x 12' in length on the top side of the 4" pipe above the Ring Header. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces.

BAY 6 (G): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. An abandoned channel support member has surface rust. The abandoned channel member is located on the top of the Ring Header near the connection of the header to the down comer. Area on top face of Ring Header at the connection of the down comer has an area approximately 4' -0" x 6' -0", of rust bleed through the thin primer coat of CZ-11. Two 5" diameter plug plates (approx. 1/2:" thick) have minor surface rust on them. Top face of the Ring Header near the down comer has rust bloom through the CZ-11; the area is approximately 3' -0" x 5' -0" in length. At the stiffener for

the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces.

BAY 7 (H): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Surface rust approximately 1" x 8' in length on the top side of the 4" pipe above the Ring Header.

BAY 8 (I): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Surface rust found on one of the structural plates (fin) around the Ring Header at the connection to the down comer. Area is approximately 6" x 2' -0".

BAY 9 (J): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Rust bloom on the top face of the 4" pipe line above the Ring Header. The rust colored area on the pipe line is approximately 2" x (the length of the bay). Surface Rust 6" x 3' in length on Ring Header Support Plate (side facing inner wall of the Torus). Ring Girder to torus wall, interior and exterior have area of corrosion approximately 2 square feet at the 9/8 Ring Girder locations. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces.

BAY 10 (K): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Abandoned wide flange support has minor surface rust. Rust bleeding through the primer coat of CZ-11 on the top face of the Ring Header toward Bay 11. The rust area is approximately 2 ' -0" x 5' -0". Located on the face of the Torus ceiling above the ring header, leaving Bay 10, minor rust bleed through in an area approximately 2' -0" x 3' -0". Interior wall has corrosion at the Ring Girder. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Rust bloom on the top face of the 4" pipe line above the Ring Header. The rust area on the line is approximately 2" x 4' -0".

BAY 11 (L): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Pipe support welded to the outer wall and connected to an 8" diameter pipe has surface rust. Horizontal monorail support above the Ring Header and connected to the structural stiffener plate between Bays 11 & 12, has surface rust over an area approximately 6' -0" square feet (6" x 12' in length). Area 4' -0" above the water line on a 12" diameter pipe, the paint is thinner in thickness and has surface rust bleeding through the primer coat of CZ-11. The piping is running at a 45 degree angle. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. RCIC pipe has

surface corrosion at both ends of the rolled fittings near the torus ceiling penetration. Nodules and surface corrosion at waterline prevalent on all surfaces. Rust bloom on the top face of the 4" pipe line above the Ring Header. The rust area on the line is approximately 2" x (the length of the bay).

BAY 12 (M): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Structural steel for the walk way attached to the inner wall just above the waterline is covered with surface rust. Horizontal monorail support above the Ring Header and connected to the structural stiffener plate between Bays 12 & 13, has surface rust over an area approximately 0.5 square feet (2" x 3' in length). Two 5" diameter plug plates (approx. ½ " thick) have minor rust bloom on them. Ring girder attached to the interior wall has two welded lugs attached to it about 2' -0 above the waterline. The lugs and the area around them 2' -0" x 2' -0" have minor rust about them. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present Nodules and surface corrosion at waterline prevalent on all surfaces. Minor corrosion on bottom of Vent Header and associated Downcomer adjacent to Vent Line to Vent Header Tee (right of Tee as viewed from the inside).

BAY 13 (N): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Structural steel for the walk way attached to the inner wall just above the waterline is covered heavily with surface rust. Horizontal monorail support above the Ring Header and connected to the structural stiffener plate between Bays 12 & 13 and 13 & 14, has surface rust over an area approximately 6' -0" square feet. One 5" diameter plug plates (approx. 1/2" thick) have minor rust bloom on them. Nodules and surface corrosion at waterline prevalent on all surfaces. Adherent surface corrosion bleeding through the previously repaired area at the vent header to downcomer junction.

BAY 14 (0): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Structural steel for the walk way attached to the inner wall just above the waterline is covered with surface rust. Horizontal monorail support above the Ring Header and connected to the structural stiffener plate between Bays 13 & 14, has surface rust over an area approximately 6' -0" square feet. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Two 5" diameter plug plates (approx. ½ " thick) have minor rust bloom on them.

BAY 15 (P): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Structural steel for the walk way attached to the inner wall just above the waterline is covered with surface rust. Minor surface rust discovered on the ring girder next to the inner wall about 3 feet above the water level. The surface rust is approximately 6" x 2' - 0". Two 5" diameter plug plates (approx. 1/2" thick) have minor surface rust on them. At the stiffener for

the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Outer and bottom surface of Ring Header and associated Downcomers exhibit loss of coating with minor corrosion several areas with no metal loss.

BAY 16 (A): The primer coating of CZ-11 applied to the Ring Header, Torus interior above the water line is good. Surface rust approximately 6" x 2' -0" found on one of the structural plates (fin) around the Ring Header at the connection to the down comer. At the stiffener for the vent header to downcomer there is tightly adherent corrosion present. Nodules and surface corrosion at waterline prevalent on all surfaces. Surface rust approximately 2" x 4' in length on the top side of the 4" pipe above the Ring Header.

Torus Exterior Inspection

Bay 3 (D) Elev. 227'-6": Penetration 16X-206D1 for Torus Liquid Level is corroded at the nozzle to torus shell connection. 23HPI-958 valve is located next to the penetration on the 1" line.

Bay 4 (E) Elev. 227'-6": Penetration 16X-227B, the Core Spray Suction Nozzle has surface corrosion at the nozzle to Torus Shell interface.

Bay 6 (G) Elev. 262': Belzona and Oil spilled on torus shell. Appears to originate from 23MOV-19. Belzona or other liquid metal was used to attach strain gauges on actuators sometime in the past. Oil appears to have also leaked form the valve.

Bay 8 (I) Elev. 227'-6": 8" x 48" strip of shell has surface corrosion. Appears the coating was intentionally removed. The location is next to the I/J support saddle.

Bay 10 (K) Elev. 227'-6": Four spots of corrosion were observed, randomly distributed. Sized at 1/2 SF, 1/4 SF, 1/8 SF and 1/4 SF.

Bay 11 (L) Elev. 227'-6": Torus Liquid Level I" line is corroded at the nozzle to torus shell interface next to valve 23HPI-956.

Bay 12 (M) Elev. 227'-6": Random small spots of surface corrosion on exterior shell of torus.

Drywell Head Inspection

The Drywell Head was inspected from the refuel floor and had been placed upon the cavity shield blocks. The exterior has minor chipping at the flange location, and generally dispersed chipping throughout the exterior with only a few spots of tightly adhering surface corrosion. In general, the primer remains intact serving as a barrier to continued corrosion. Torus and Drywell exterior coatings are not

included in strainer debris loading calculations because they cannot contribute to strainer clogging.

The Drywell Head interior coating is in very good shape with no signs of peeling or blistering.

The RO21 ST-15B inspection of the interior surfaces of the drywell and torus identified some additional coating failures. For analysis, these failed coatings are assumed to reside in the torus and contribute to ECCS Strainer loading. Calculation A384.F02-02 allows 170 lbm of additional coating debris generated during the design base LOCA. This additional loading reduces this margin to 160.3 lbm leaving a significant margin for future coating failure. EC 52964 was procedurally developed to document the evaluation of the inspection results and concludes that the identified coating degradation does not adversely impact the operability of the ECCS Strainers.

3.6 License Renewal Aging Management

FSAR Section 16.10 “Supplement for Renewed Operating License,” contains the FSAR Supplement as required by 10 CFR 54.21(d) for the JAF License Renewal Application (LRA). The NRC issued SER NUREG-1905, “Safety Evaluation Report Related to the License Renewal of James A. FitzPatrick Nuclear Power Plant (Reference 23) that provided their safety evaluation of the JAF LRA.

The aging management activity descriptions presented in this appendix represent commitments for managing aging of the in-scope systems, structures and components during the period of extended operation.

As part of the license renewal effort, it had to be demonstrated that the aging effects applicable for the components and structures within the scope of license renewal would be adequately managed during the period of extended operation.

In many cases, existing activities were found adequate for managing aging effects during the period of extended operation. In some cases, aging management reviews revealed that existing activities required enhancement to adequately manage applicable aging effects. In a few cases, new activities were developed to provide added assurance that aging effects are adequately managed.

The following programs/activities are credited with the aging management of the Primary Containment (Drywell and Torus).

Inservice Inspection - Containment Inservice Inspection (CII) Program

The Containment Inservice Inspection Program outlines the requirements for the inspection of Class MC pressure-retaining components (primary containment) and their integral attachments in accordance with the requirements of 10 CFR 50.55a and the

ASME Boiler and Pressure Vessel Code, 2001 Edition through the 2003 Addenda, Section XI, Subsection IWE.

The primary inspection method for the primary containment and its integral attachments is visual examination. Visual examinations are performed either directly or remotely with illumination and resolution suitable for the local environment to assess general conditions that may affect either the containment structural integrity or leak tightness of the pressure retaining component. The program includes augmented ultrasonic exams to measure wall thickness of the containment drywell structure.

Containment Leak Rate Program

As described in 10 CFR 50, Appendix J, containment leak rate tests are required to assure that (a) leakage through primary reactor containment and systems and components penetrating primary containment shall not exceed allowable values specified in technical specifications or associated bases, and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating primary containment. Corrective actions are taken if leakage rates exceed acceptance criteria.

3.7 NRC SER Limitations and Conditions

3.7.1 Limitations and Conditions Applicable to NEI 94-01 Revision 2-A

The NRC staff found that the use of NEI TR 94-01, Revision 2, was acceptable for referencing by licensees proposing to amend their TSs to permanently extend the ILRT surveillance interval to 15 years, provided the following conditions as listed in Table 3.7.1-1 were satisfied:

Table 3.7.1-1, NEI 94-01 Revision 2-A Limitations and Conditions

Limitation/Condition (From Section 4.0 of SE)	**JAF Response**
For calculating the Type A leakage rate, the licensee should use the definition in the NEI TR 94-01, Revision 2, in lieu of that in ANSI/ANS-56.8-2002. (Refer to SE Section 3.1.1.1.)	JAF will utilize the definition in NEI 94-01 Revision 3-A, Section 5.0. This definition has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01.
The licensee submits a schedule of containment inspections to be performed prior to and between Type A tests. (Refer to SE Section 3.1.1.3.)	Surveillance Test ST-15B, Suppression Chamber and Drywell Deterioration Inspection, is performed each refueling outage. Reference Section 3.4.1 and Table 3.4.3-1

Table 3.7.1-1, NEI 94-01 Revision 2-A Limitations and Conditions	
Limitation/Condition (From Section 4.0 of SE)	**JAF Response**
The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	Reference Section 3.4.3 and Section 3.5 of this submittal.
The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.)	There are no major modifications planned that would require the performance of a Type A ILRT or a Structural Integrity Test (SIT).
The normal Type A test interval should be less than 15 years. If a licensee has to utilize the provision of Section 9.1 of NEI TR 94-01, Revision 2, related to extending the ILRT interval beyond 15 years, the licensee must demonstrate to the NRC staff that it is an unforeseen emergent condition. (Refer to SE Section 3.1.1.2.)	JAF will follow the requirements of NEI 94-01 Revision 3-A, Section 9.1. This requirement has remained unchanged from Revision 2-A to Revision 3-A of NEI 94-01. In accordance with the requirements of 94-01 Revision 2-A, SER Section 3.1.1.2, JAF will also demonstrate to the NRC staff that an unforeseen emergent condition exists in the event an extension beyond the 15-year interval is required.
For plants licensed under 10 CFR Part 52, applications requesting a permanent extension of the ILRT surveillance interval to 15 years should be deferred until after the construction and testing of containments for that design have been completed and applicants have confirmed the applicability of NEI 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. JAF was not licensed under 10 CFR Part 52.

3.7.2 Limitations and Conditions Applicable to NEI 94-01 Revision 3-A

The NRC staff found that the guidance in NEI TR 94-01, Revision 3, was acceptable for referencing by licensees in the implementation for the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J. However, the NRC staff identified two conditions on the use of NEI TR 94-01, Revision 3 (Reference NEI 94-01 Revision 3-A, NRC SER 4.0, Limitations and Conditions):

Topical Report Condition 1

NEI TR 94-01, Revision 3, is requesting that the allowable extended interval for Type C LLRTs be increased to 75 months, with a permissible extension (for non-routine emergent conditions) of nine months (84 months total). The staff is allowing the extended interval for Type C LLRTs be increased to 75 months with the requirement

that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit. In addition, a corrective action plan shall be developed to restore the margin to an acceptable level. The staff is also allowing the non-routine emergent extension out to 84-months as applied to Type C valves at a site, with some exceptions that must be detailed in NEI TR 94-01, Revision 3. At no time shall an extension be allowed for Type C valves that are restricted categorically (e.g., BWR MSIVs), and those valves with a history of leakage, or any valves held to either a less than maximum interval or to the base refueling cycle interval. Only non-routine emergent conditions allow an extension to 84 months.

Response to Condition 1

Condition 1 presents three (3) separate issues that are required to be addressed. They are as follows:

- ISSUE 1 - The allowance of an extended interval for Type C LLRTs of 75 months carries the requirement that a licensee's post-outage report include the margin between the Type B and Type C leakage rate summation and its regulatory limit.

- ISSUE 2 - In addition, a corrective action plan shall be developed to restore the margin to an acceptable level.

- ISSUE 3 - Use of the allowed 9-month extension for eligible Type C valves is only authorized for non-routine emergent conditions.

Response to Condition 1, Issue 1

The post-outage report shall include the margin between the Type B and Type C Minimum Pathway Leak Rate (MNPLR) summation value, as adjusted to include the estimate of applicable Type C leakage understatement, and its regulatory limit of 0.60 L_a.

Response to Condition 1, Issue 2

When the potential leakage understatement adjusted Type B and C MNPLR total is greater than the JAF leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and determination of a corrective action plan shall be prepared to restore the leakage summation margin to less than the JAF leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues so as to maintain an acceptable level of margin.

Response to Condition 1, Issue 3

JAF will apply the 9-month grace period only to eligible Type C components and only for non-routine emergent conditions. Such occurrences will be documented in the record of tests.

Topical Report Condition 2

The basis for acceptability of extending the ILRT interval out to once per 15 years was the enhanced and robust primary containment inspection program and the local leakage rate testing of penetrations. Most of the primary containment leakage experienced has been attributed to penetration leakage and penetrations are thought to be the most likely location of most containment leakage at any time. The containment leakage condition monitoring regime involves a portion of the penetrations being tested each refueling outage, nearly all LLRTs being performed during plant outages. For the purposes of assessing and monitoring or trending overall containment leakage potential, the as-found minimum pathway leakage rates for the just tested penetrations are summed with the as-left minimum pathway leakage rates for penetrations tested during the previous 1 or 2 or even 3 refueling outages. Type C tests involve valves, which in the aggregate, will show increasing leakage potential due to normal wear and tear, some predictable and some not so predictable. Routine and appropriate maintenance may extend this increasing leakage potential. Allowing for longer intervals between LLRTs means that more leakage rate test results from farther back in time are summed with fewer just tested penetrations and that total used to assess the current containment leakage potential. This leads to the possibility that the LLRT totals calculated understate the actual leakage potential of the penetrations. Given the required margin included with the performance criterion and the considerable extra margin most plants consistently show with their testing, any understatement of the LLRT total using a 5-year test frequency is thought to be conservatively accounted for. Extending the LLRT intervals beyond 5 years to a 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI TR 94-01, Revision 3, Section 12.1.

When routinely scheduling any LLRT valve interval beyond 60-months and up to 75-months, the primary containment leakage rate testing program trending or monitoring must include an estimate of the amount of understatement in the Type B and C total, and must be included in a licensee's post-outage report. The report must include the reasoning and determination of the acceptability of the extension, demonstrating that the LLRT totals calculated represent the actual leakage potential of the penetrations.

Response to Condition 2

Condition 2 presents two (2) separate issues that are required to be addressed. They are as follows:

- ISSUE 1 - Extending the LLRT intervals beyond 5 years to a 75-month interval should be similarly conservative provided an estimate is made of the potential understatement and its acceptability determined as part of the trending specified in NEI TR 94-01, Revision 3, Section 12.1.

- ISSUE 2 - When routinely scheduling any LLRT valve interval beyond 60-months and up to 75-months, the primary containment leakage rate testing program trending or monitoring must include an estimate of the amount of understatement in the Type B and C total, and must be included in a licensee's post-outage report. The report must include the reasoning and determination of the acceptability of the extension, demonstrating that the LLRT totals calculated represent the actual leakage potential of the penetrations.

Response to Condition 2, Issue 1

The change in going from a 60-month extended test interval for Type C tested components to a 75-month interval, as authorized under NEI 94-01, Revision 3-A, represents an increase of 25% in the LLRT periodicity. As such, JAF will conservatively apply a potential leakage understatement adjustment factor of 1.25 to the As-Left leakage total for each Type C component currently on the 75-month extended test interval. This will result in a combined conservative Type C total for all 75-month LLRT's being "carried forward" and will be included whenever the total leakage summation is required to be updated (either while on line or following an outage). When the potential leakage understatement adjusted leak rate total for those Type C components being tested on a 75-month extended interval is summed with the non-adjusted total of those Type C components being tested at less than the 75-month interval and the total of the Type B tested components, if the MNPLR is greater than the JAF leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.6 L_a, then an analysis and corrective action plan shall be prepared to restore the leakage summation value to less than the JAF leakage limit. The corrective action plan shall focus on those components which have contributed the most to the increase in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

Response to Condition 2, Issue 2

If the potential leakage understatement adjusted leak rate MNPLR is less than the JAF leakage summation limit of 0.50 L_a, then the acceptability of the 75-month LLRT extension for all affected Type C components has been adequately demonstrated and the calculated local leak rate total represents the actual leakage potential of the penetrations.

In addition to Condition 1, Parts 1, 2 which deal with the MNPLR Type B and C summation margin, NEI 94-01, Revision 3-A also has a margin related requirement as contained in Section 12.1, Report Requirements.

A post-outage report shall be prepared presenting results of the previous cycle's Type B and Type C tests, and Type A, Type B and Type C tests, if performed during that outage. The technical contents of the report are generally described in ANSI/ANS-56.8-2002 and shall be available on-site for NRC review. The report shall show that the applicable performance criteria are met, and serve as a record that continuing performance is acceptable. The report shall also include the combined Type B and Type C leakage summation, and the margin between the Type B and Type C leakage rate summation and its regulatory limit. Adverse trends in the Type B and Type C leakage rate summation shall be identified in the report and a corrective action plan developed to restore the margin to an acceptable level.

At JAF, in the event an adverse trend in the aforementioned potential leakage understatement adjusted Type B and C summation is identified, then an analysis and determination of a corrective action plan shall be prepared to restore the trend and associated margin to an acceptable level. The corrective action plan shall focus on those components which have contributed the most to the adverse trend in the leakage summation value and what manner of timely corrective action, as deemed appropriate, best focuses on the prevention of future component leakage performance issues.

At JAF an adverse trend is defined as three (3) consecutive increases in the final pre-RCS Mode Change Type B and C MNPLR leakage summation values, as adjusted to include the estimate of applicable Type C leakage understatement, as expressed in terms of L_a.

3.8 Conclusion

NEI 94-01, Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, describes an NRC-accepted approach for implementing the performance-based requirements of 10 CFR Part 50, Appendix J, Option B. It incorporated the regulatory positions stated in RG 1.163 and includes provisions for extending Type A intervals to 15 years and Type C test intervals to 75 months. NEI 94-01, Revision 3-A delineates a performance-based approach for determining Type A, Type B, and Type C containment leakage rate surveillance test frequencies. JAF is adopting the guidance of NEI 94-01, Revision 3-A, and the conditions and limitations specified in NEI 94-01, Revision 2-A, for the JAF 10 CFR Part 50, Appendix J testing program plan.

Based on the previous ILRT tests conducted at JAF, it may be concluded that the permanent extension of the containment ILRT interval from 10 to 15 years represents minimal risk to increased leakage. The risk is minimized by continued Type B and Type C testing performed in accordance with Option B of 10 CFR Part 50, Appendix J and the overlapping inspection activities performed as part of the following JAF inspection programs:

- Containment Inservice Inspection Program (IWE)

- Containment Inspections per TS SR 3.6.1.1.1, Suppression Chamber and Drywell Deterioration Inspection
- Inspection of Primary Containment Coatings

This experience is supplemented by risk analysis studies, including the JAF risk analysis provided in Attachment 4. The findings of the risk assessment confirm the general findings of previous studies, on a plant-specific basis, that extending the ILRT interval from ten to 15 years results in a very small change to the JAF risk profiles.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

The proposed change has been evaluated to determine whether applicable regulations and requirements continue to be met.

10 CFR 50.54(o) requires primary reactor containments for water-cooled power reactors to be subject to the requirements of Appendix J to 10 CFR Part 50, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.” Appendix J specifies containment leakage testing requirements, including the types required to ensure the leak-tight integrity of the primary reactor containment and systems and components which penetrate the containment. In addition, Appendix J discusses leakage rate acceptance criteria, test methodology, frequency of testing and reporting requirements for each type of test.

The adoption of the Option B performance-based containment leakage rate testing for Type A, Type B and Type C testing did not alter the basic method by which Appendix J leakage rate testing is performed; however, it did alter the frequency at which Type A, Type B, and Type C containment leakage tests must be performed. Under the performance-based option of 10 CFR Part 50, Appendix J, the test frequency is based upon an evaluation that reviewed “as-found” leakage history to determine the frequency for leakage testing which provides assurance that leakage limits will be maintained. The change to the Type A test frequency did not directly result in an increase in containment leakage. Similarly, the proposed change to the Type C test frequency will not directly result in an increase in containment leakage.

EPRI TR-1009325, Revision 2, provided a risk impact assessment for optimized ILRT intervals up to 15 years, utilizing current industry performance data and risk informed guidance. NEI 94-01, Revision 3-A, Section 9.2.3.1 states that Type A ILRT intervals of up to 15 years are allowed by this guideline. The Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, EPRI Report 1018243 (Formerly TR-1009325, Revision 2) indicates that, in general, the risk impact associated with ILRT interval extensions for intervals up to 15 years is small. However, plant-specific confirmatory analyses are required.

The NRC staff reviewed NEI TR 94-01, Revision 2, and EPRI Report No. 1009325, Revision 2. For NEI TR 94-01, Revision 2, the NRC staff determined that it described an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J. This guidance includes provisions for extending Type A ILRT intervals to up to 15 years and incorporates the regulatory positions stated in RG 1.163. The NRC staff finds that the Type A testing methodology as described in ANSI/ANS-56.8-2002, and the modified testing frequencies recommended by NEI TR 94-01, Revision 2, serves to ensure continued leakage integrity of the containment structure. Type B and Type C testing ensures that individual penetrations are essentially leak tight. In addition, aggregate Type B and Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

For EPRI Report No. 1009325, Revision 2, a risk-informed methodology using plant-specific risk insights and industry ILRT performance data to revise ILRT surveillance frequencies, the NRC staff finds that the proposed methodology satisfies the key principles of risk-informed decision making applied to changes to TSs as delineated in RG 1.177 and RG 1.174. The NRC staff, therefore, found that this guidance was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing, subject to the limitations and conditions noted in Section 4.0 of the Safety Evaluation Report (SER).

The NRC staff reviewed NEI TR 94-01, Revision 3, and determined that it described an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR Part 50, Appendix J, as modified by the conditions and limitations summarized in Section 4.0 of the associated Safety Evaluation. This guidance included provisions for extending Type C LLRT intervals up to 75 months. Type C testing ensures that individual containment isolation valves are essentially leak tight. In addition, aggregate Type C leakage rates support the leakage tightness of primary containment by minimizing potential leakage paths.

The NRC staff, therefore, found that this guidance, as modified to include two limitations and conditions, was acceptable for referencing by licensees proposing to amend their TS in regards to containment leakage rate testing. Any applicant may reference NEI TR 94-01, Revision 3, as modified by the associated SER and approved by the NRC, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, in a licensing action to satisfy the requirements of Option B to 10 CFR Part 50, Appendix J.

4.2 Precedent

This license amendment request is similar in nature to the following license amendments previously authorized by the NRC to extend the Type A test frequency to 15 years and the Type C test frequency to 75 months:

- Surry Power Station, Units 1 and 2 (Reference 24)
- Donald C. Cook Nuclear Plant, Units 1 and 2 (Reference 25)
- Beaver Valley Power Station, Unit Nos. 1 and 2 (Reference 26)
- Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 and 2 (Reference 27)

4.3 No Significant Hazards Consideration

Entergy Operations, Inc. (Entergy) has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed amendment to the TS involves the extension of the JAF Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months. The current Type A test interval of 120 months (10 years) would be extended on a permanent basis to no longer than 15 years from the last Type A test. The current Type C test interval of 60 months for selected components would be extended on a performance basis to no longer than 75 months. Extensions of up to nine months (total maximum interval of 84 months for Type C tests) are permissible only for non-routine emergent conditions. The proposed extension does not involve either a physical change to the plant or a change in the manner in which the plant is operated or controlled. The containment is designed to provide an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment for postulated accidents. As such, the containment and the testing requirements invoked to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident, and do not involve the prevention or identification of any precursors of an accident. The change in dose risk for changing the Type A test frequency from three-per-ten years to once-per-fifteen-years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.0087 person-rem/year. EPRI Report No. 1009325, Revision 2-A states that a very small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of the risk assessment for this amendment meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible. Therefore, this proposed extension does not involve a significant increase in the probability of an accident previously evaluated.

   As documented in NUREG-1493, Type B and C tests have identified a very large percentage of containment leakage paths, and the percentage of containment

leakage paths that are detected only by Type A testing is very small. The JAF Type A test history supports this conclusion.

The integrity of the containment is subject to two types of failure mechanisms that can be categorized as: (1) activity based, and; (2) time based. Activity based failure mechanisms are defined as degradation due to system and/or component modifications or maintenance. Local leak rate test requirements and administrative controls such as configuration management and procedural requirements for system restoration ensure that containment integrity is not degraded by plant modifications or maintenance activities. The design and construction requirements of the containment combined with the containment inspections performed in accordance with ASME Section XI, the Maintenance Rule, and TS requirements serve to provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by a Type A test. Based on the above, the proposed extensions do not significantly increase the consequences of an accident previously evaluated.

The proposed amendment also deletes exceptions previously granted to allow one-time extensions of the ILRT test frequency for JAF. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action that has no effect on any component and no impact on how the unit is operated.

Therefore, the proposed change does not result in a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed amendment to the TS involves the extension of the JAF Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months. The containment and the testing requirements to periodically demonstrate the integrity of the containment exist to ensure the plant's ability to mitigate the consequences of an accident do not involve any accident precursors or initiators. The proposed change does not involve a physical change to the plant (i.e., no new or different type of equipment will be installed) or a change to the manner in which the plant is operated or controlled.

   The proposed amendment also deletes exceptions previously granted to allow one-time extensions of the ILRT test frequency for JAF. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action that does not result in any change in how the unit is operated.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The proposed amendment to TS 5.5.6 involves the extension of the JAF Type A containment test interval to 15 years and the extension of the Type C test interval to 75 months for selected components. This amendment does not alter the manner in which safety limits, limiting safety system set points, or limiting conditions for operation are determined. The specific requirements and conditions of the TS Containment Leak Rate Testing Program exist to ensure that the degree of containment structural integrity and leak-tightness that is considered in the plant safety analysis is maintained. The overall containment leak rate limit specified by TS is maintained.

   The proposed change involves only the extension of the interval between Type A containment leak rate tests and Type C tests for JAF. The proposed surveillance interval extension is bounded by the 15-year ILRT Interval and the 75-month Type C test interval currently authorized within NEI 94-01, Revision 3-A. Industry experience supports the conclusion that Type B and C testing detects a large percentage of containment leakage paths and that the percentage of containment leakage paths that are detected only by Type A testing is small. The containment inspections performed in accordance with ASME Section XI, TS and the Maintenance Rule serve to provide a high degree of assurance that the containment would not degrade in a manner that is detectable only by Type A testing. The combination of these factors ensures that the margin of safety in the plant safety analysis is maintained. The design, operation, testing methods and acceptance criteria for Type A, B, and C containment leakage tests specified in applicable codes and standards would continue to be met, with the acceptance of this proposed change, since these are not affected by changes to the Type A and Type C test intervals.

   The proposed amendment also deletes exceptions previously granted to allow one time extensions of the ILRT test frequency for JAF. These exceptions were for activities that would have already taken place by the time this amendment is approved; therefore, their deletion is solely an administrative action and does not change how the unit is operated and maintained. Thus, there is no reduction in any margin of safety.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

4.4 Conclusion

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission’s regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

1. Regulatory Guide 1.163, Performance-Based Containment Leak-Test Program, September 1995.

2. Revision 3-A to Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, NEI 94-01, July 2012.

3. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, May 2011.

4. An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, Regulatory Guide 1.200, Revision 2, March 2009.

5. NEI 94-01, Revision 0, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, July 1995.

6. NUREG-1493, Performance-Based Containment Leak-Test Program, July 1995.

7. Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals, EPRI, Palo Alto, CA EPRI TR-104285, August 1994.

8. NEI 94-01, Revision 2-A, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J, October 2008.

9. Letter from M. J. Maxin (NRC) to J. C. Butler (NEI), dated June 25, 2008, Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J" and Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, August 2007, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals" (TAC No. MC9663).

10. Letter from S. Bahadur (NRC) to B. Bradley (NEI), dated June 8, 2012, Final Safety Evaluation of Nuclear Energy Institute (NEI) Report 94-01, Revision 3, Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J (TAC No. ME2164).

11. Letter to W. Cahill from K. Cotton (NRC) dated December 6, 1996. Issuance of Amendment 239 For James A. FitzPatrick Nuclear Power Plant.

12. Letter from J. Brons to Document Control Desk (NRC). Response to Generic Letter 87-05 – Potential Degradation of Mark I Drywells due to Water Leakage, dated May 11, 1987, JPN-87-025.

13. Letter to W. Cahill from K. Cotton (NRC) dated October 4, 1996. Issuance of Amendment 234 For James A. FitzPatrick Nuclear Power Plant.

14. Letter from J Knubel to U.S. NRC Document Control Desk dated November 10, 1998, Response to NRC Generic Letter 98-04. (JPN-98-047)

15. Letter to J. Knuber from G. Vissing (NRC) dated April 14, 2000. James A. FitzPatrick Nuclear Power Plant - Issuance of Amendment Re: Changes to The Technical Specifications Regarding the Allowed Containment Leakage Rate.

16. Letter to M. Kansler from G. Vissing (NRC) dated August 13, 2002. James A. FitzPatrick Nuclear Power Plant - Amendment Re: Changes to The Technical Specification Leakage Limit for The Main Steam Isolation Valves from an Individual to an Aggregate Limit.

17. Letter to M. Kansler from P. Milano (NRC) dated September 28, 2004. James A. FitzPatrick Nuclear Power Plant - Amendment Re: One-Time Extension of Containment Integrated Leakage Rate Test Interval.

18. Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard, NEI 05-04, Revision 2, November 2008.

19. NRC Generic Letter 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities -10 CFR 50.54(f), Supplement 4," June 28, 1991.

20. Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals, Revision 2-A of 1009325, EPRI, Palo Alto, CA. 1018243, October 2008.

21. Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals, Revision 4, developed for NEI by EPRI and Data Systems and Solutions, November 2001.

22. Professional Loss Control, Inc., Fire-Induced Vulnerability Evaluation (FIVE) Methodology Plant Screening Guide, EPRI TR-100370, Electric Power Research Institute, Final Report, April 1992.

23. NUREG-1905, Safety Evaluation Report Related to the License Renewal of James A. FitzPatrick Nuclear Power Plant, April 2008 (ML081510826).

24. ML14148A235, Letter to D. Heacock from S. Williams (NRC) dated July 3, 2014. Surry Power Station, Units 1 And 2- Issuance of Amendment Regarding the Containment Type A And Type C Leak Rate Tests.

25. ML15072A264, Letter to L. Weber from A. Dietrich (NRC) dated March 30, 2015. Donald C. Cook Nuclear Plant, Units 1 And 2 -Issuance of Amendments Re: Containment Leakage Rate Testing Program.

26. ML15078A058, Letter to E. Larson from T. Lamb (NRC) dated April 8, 2015. Beaver Valley Power Station, Unit Nos. 1 And 2 -Issuance of Amendment Re: License Amendment Request to Extend Containment Leakage Rate Test Frequency.

27. ML15154A661, Letter to G. Gellrich from A. Chereskin (NRC) dated July 16, 2015. Calvert Cliffs Nuclear Power Plant, Unit Nos. 1 And 2 -Issuance of Amendments Re: Extension Of Containment Leakage Rate Testing Frequency.

28. Parkinson, W. J., “EPRI Fire PRA Implementation Guide”, prepared by Science Applications International Corporation for Electric Power Research Institute, EPRI TR-105928, December 1995.

29. Engineering Report No. JAF-RPT-MISC-02211, Revision 0, James A. FitzPatrick Nuclear Power Plant, “Individual Plant Examination of External Events,” June 1996.

30. ASME/American Nuclear Society, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications, ASME/ANS RA-Sa-2009, March 2009.

31. U.S. Nuclear Regulatory Commission, NUREG-1742 “Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program,” Volume 1 & 2, Final Report, April 2002.

32. Letter from Mr. C. H. Cruse (Constellation Nuclear, Calvert Cliffs Nuclear Power Plant) to U.S. Nuclear Regulatory Commission, Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension, Accession Number ML020920100, March 27, 2002.

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Attachment 2

Proposed Technical Specification Changes (Markup)

<u>2 Pages</u>

FOL Page 3

TS Page 5.5-5

(4) ENO pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use, at any time, any byproduct, source and special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration; or associated with radioactive apparatus, components or tools.

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

ENO is authorized to operate the facility at steady state reactor core power levels not in excess of 2536 megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No.~~309~~ , are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Fire Protection

ENO shall implement and maintain in effect all provisions of the approved fire protections program as described in the Final Safety Analysis Report for the facility and as approved in the SER dated November 20, 1972; the SER Supplement No. 1 dated February 1, 1973; the SER Supplement No. 2 dated October 4, 1974; the SER dated August 1, 1979; the SER Supplement dated October 3, 1980; the SER Supplement dated February 13, 1981; the NRC Letter dated February 24, 1981; Technical Specification Amendments 34 (dated January 31, 1978), 80 (dated May 22, 1984), 134 (dated July 19, 1989), 135 (dated September 5, 1989), 142 (dated October 23, 1989), 164 (dated August 10, 1990), 176 (dated January 16, 1992), 177 (dated February 10, 1992), 186 (dated February 19, 1993), 190 (dated June 29, 1993), 191 (dated July 7, 1993), 206 (dated February 28, 1994) and 214 (dated June 27, 1994); and NRC Exemptions and associated safety evaluations dated April 26, 1983, July 1, 1983, January 11, 1985, April 30, 1986, September 15, 1986 and September 10, 1992 subject to the following provision:

5.5 Programs and Manuals (continued)

5.5.6 Primary Containment Leakage Rate Testing Program

This program implements the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in ~~Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995,~~ as modified by the following exceptions:

NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008,

- ~~NEI 94-01-1995, Section 9.2.3: The first Type A test performed after the March 7, 1995 Type A test shall be performed no later than March 7, 2010.~~
- Type C testing of valves not isolable from the containment free air space may be accomplished by pressurization in the reverse direction, provided that testing in this manner provides equivalent or more conservative results than testing in the accident direction. If potential atmospheric leakage paths (e.g., valve stem packing) are not subjected to test pressure, the portions of the valve not exposed to test pressure shall be subjected to leakage rate measurement during regularly scheduled Type A testing. A list of these valves, the leakage rate measurement method, and the acceptance criteria, shall be contained in the Program.

a. The peak primary containment internal pressure for the design basis loss of coolant accident, P_a, is 45 psig.

b. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 1.5% of containment air weight per day.

c. The leakage rate acceptance criteria are:

1. Primary containment leakage rate acceptance criteria is $\leq 1.0\ L_a$. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests, and $\leq 0.75\ L_a$ for the Type A tests.

2. Air lock testing acceptance criteria are:

(a) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$; and

(b) For each door seal, leakage rate is ≤ 120 scfd when tested at $\geq P_a$.

(continued)

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Attachment 3

Revised Technical Specification Pages (Clean)

<u>2 Pages</u>

FOL Page 3

TS Page 5.5-5

(4) ENO pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use, at any time, any byproduct, source and special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration; or associated with radioactive apparatus, components or tools.

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

ENO is authorized to operate the facility at steady state reactor core power levels not in excess of 2536 megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. , are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Fire Protection

ENO shall implement and maintain in effect all provisions of the approved fire protections program as described in the Final Safety Analysis Report for the facility and as approved in the SER dated November 20, 1972; the SER Supplement No. 1 dated February 1, 1973; the SER Supplement No. 2 dated October 4, 1974; the SER dated August 1, 1979; the SER Supplement dated October 3, 1980; the SER Supplement dated February 13, 1981; the NRC Letter dated February 24, 1981; Technical Specification Amendments 34 (dated January 31, 1978), 80 (dated May 22, 1984), 134 (dated July 19, 1989), 135 (dated September 5, 1989), 142 (dated October 23, 1989), 164 (dated August 10, 1990), 176 (dated January 16, 1992), 177 (dated February 10, 1992), 186 (dated February 19, 1993), 190 (dated June 29, 1993), 191 (dated July 7, 1993), 206 (dated February 28, 1994) and 214 (dated June 27, 1994); and NRC Exemptions and associated safety evaluations dated April 26, 1983, July 1, 1983, January 11, 1985, April 30, 1986, September 15, 1986 and September 10, 1992 subject to the following provision:

5.5.6 Primary Containment Leakage Rate Testing Program

This program implements the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-based Option of 10 CFR Part 50, Appendix J" Revision 3-A dated July 2012, and the conditions and limitations specified in NEI 94-01 Revision 2-A, dated October 2008, as modified by the following exceptions:

- Type C testing of valves not isolable from the containment free air space may be accomplished by pressurization in the reverse direction, provided that testing in this manner provides equivalent or more conservative results than testing in the accident direction. If potential atmospheric leakage paths (e.g., valve stem packing) are not subjected to test pressure, the portions of the valve not exposed to test pressure shall be subjected to leakage rate measurement during regularly scheduled Type A testing. A list of these valves, the leakage rate measurement method, and the acceptance criteria, shall be contained in the Program.

a. The peak primary containment internal pressure for the design basis loss of coolant accident, P_a, is 45 psig.

b. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 1.5% of containment air weight per day.

c. The leakage rate acceptance criteria are:

1. Primary containment leakage rate acceptance criteria is $\leq$ 1.0 L_a. During plant startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq$ 0.60 L_a for the Type B and Type C tests, and $\leq$ 0.75 L_a for the Type A tests.

2. Air lock testing acceptance criteria are:

(a) Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq$ P_a; and

(b) For each door seal, leakage rate is $\leq$ 120 scfd when tested at $\geq$ P_a.

(continued)

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Attachment 4

JAFNPP Evaluation of Risk Significance of Permanent ILRT Extension

52 Pages

JENSEN HUGHES

Advancing the Science of Safety

James A. FitzPatrick Nuclear Power Plant:
Evaluation of Risk Significance of Permanent ILRT Extension

33010-CALC-01

Prepared for:

James A. FitzPatrick Nuclear Power Plant

Project Title: Permanent ILRT Extension

Revision: 0

	Name and Date
Preparer: Justin Sattler	Digitally signed by Justin Sattler Date: 2015.08.17 13:16:53-05'00'
Reviewer: Matthew Johnson	Digitally signed by Matt Johnson Date: 2015.08.17 13:35:29-05'00'
Reviewer: Kelly Wright	Digitally signed by Kelly Wright Date: 2015.08.17 13:31:43-05'00'
Review Method	Design Review ☒ Alternate Calculation ☐
Approved by: Richard Anoba	Richard Anoba 2015.08.17 14:40:04 -04'00'

REVISION RECORD SUMMARY

Revision	Revision Summary
0	Initial Issue

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1.0 PURPOSE

The purpose of this analysis is to provide a risk assessment of permanently extending the currently allowed containment Type A Integrated Leak Rate Test (ILRT) to fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for the James A. FitzPatrick Nuclear Power Plant (JAF). The risk assessment follows the guidelines from NEI 94-01, Revision 3-A [Reference 1], the methodology used in EPRI TR-104285 [Reference 2], the NEI “Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals” from November 2001 [Reference 3], the NRC regulatory guidance on the use of Probabilistic Risk Assessment (PRA) as stated in Regulatory Guide 1.200 as applied to ILRT interval extensions, risk insights in support of a request for a plant’s licensing basis as outlined in Regulatory Guide (RG) 1.174 [Reference 4], the methodology used for Calvert Cliffs to estimate the likelihood and risk implications of corrosion-induced leakage of steel liners going undetected during the extended test interval [Reference 5], and the methodology used in EPRI 1018243, Revision 2-A of EPRI 1009325 [Reference 24].

2.0 SCOPE

Revisions to 10CFR50, Appendix J (Option B) allow individual plants to extend the Integrated Leak Rate Test (ILRT) Type A surveillance testing frequency requirement from three in ten years to at least once in ten years. The revised Type A frequency is based on an acceptable performance history defined as two consecutive periodic Type A tests at least 24 months apart in which the calculated performance leakage rate was less than limiting containment leakage rate of $1L_a$.

The basis for the current 10-year test interval is provided in Section 11.0 of NEI 94-01, Revision 0, and established in 1995 during development of the performance-based Option B to Appendix J. Section 11.0 of NEI 94-01 states that NUREG-1493, “Performance-Based Containment Leak Test Program,” September 1995 [Reference 6], provides the technical basis to support rulemaking to revise leakage rate testing requirements contained in Option B to Appendix J. The basis consisted of qualitative and quantitative assessment of the risk impact (in terms of increased public dose) associated with a range of extended leakage rate test intervals. To supplement the NRC’s rulemaking basis, NEI undertook a similar study. The results of that study are documented in Electric Power Research Institute (EPRI) Research Project TR-104285, “Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals.”

The NRC report on performance-based leak testing, NUREG-1493, analyzed the effects of containment leakage on the health and safety of the public and the benefits realized from the containment leak rate testing. In that analysis, it was determined that for a representative PWR plant (i.e., Surry), that containment isolation failures contribute less than 0.1% to the latent risks from reactor accidents. Consequently, it is desirable to show that extending the ILRT interval will not lead to a substantial increase in risk from containment isolation failures for JAF.

NEI 94-01 Revision 2-A contains a Safety Evaluation Report that supports using EPRI Report No. 1009325 Revision 2-A, “Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals,” for performing risk impact assessments in support of ILRT extensions [Reference 24]. The Guidance provided in Appendix H of EPRI Report No. 1009325 Revision 2-A builds on the EPRI Risk Assessment methodology, EPRI TR-104285. This methodology is followed to determine the appropriate risk information for use in evaluating the impact of the proposed ILRT changes.

It should be noted that containment leak-tight integrity is also verified through periodic in-service

inspections conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI. More specifically, Subsection IWE provides the rules and requirements for in-service inspection of Class MC pressure-retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure-retaining components and their integral attachments in light-water cooled plants. Furthermore, NRC regulations 10 CFR 50.55a(b)(2)(ix)(E) require licensees to conduct visual inspections of the accessible areas of the interior of the containment. The associated change to NEI 94-01 will require that visual examinations be conducted during at least three other outages, and in the outage during which the ILRT is being conducted. These requirements will not be changed as a result of the extended ILRT interval. In addition, Appendix J, Type B local leak tests performed to verify the leak-tight integrity of containment penetration bellows, airlocks, seals, and gaskets are also not affected by the change to the Type A test frequency.

The acceptance guidelines in RG 1.174 are used to assess the acceptability of this permanent extension of the Type A test interval beyond that established during the Option B rulemaking of Appendix J. RG 1.174 defines very small changes in the risk-acceptance guidelines as increases in Core Damage Frequency (CDF) less than 10^{-6} per reactor year and increases in Large Early Release Frequency (LERF) less than 10^{-7} per reactor year. FitzPatrick does not credit containment overpressure for NPSH for ECCS. Therefore, the Type A test does not impact CDF, so the relevant criterion is the change in LERF. RG 1.174 also defines small changes in LERF as below 10^{-6} per reactor year. RG 1.174 discusses defense-in-depth and encourages the use of risk analysis techniques to help ensure and show that key principles, such as the defense-in-depth philosophy, are met. Therefore, the increase in the Conditional Containment Failure Probability (CCFP), which helps ensure the defense-in-depth philosophy is maintained, is also calculated.

Regarding CCFP, changes of up to 1.1% have been accepted by the NRC for the one-time requests for extension of ILRT intervals. In context, it is noted that a CCFP of 1/10 (10%) has been approved for application to evolutionary light water designs. Given these perspectives, a change in the CCFP of up to 1.5% is assumed to be small.

In addition, the total annual risk (person rem/year population dose) is examined to demonstrate the relative change in this parameter. While no acceptance guidelines for these additional figures of merit are published, examinations of NUREG-1493 and Safety Evaluation Reports (SER) for one-time interval extension (summarized in Appendix G of Reference 24) indicate a range of incremental increases in population dose that have been accepted by the NRC. The range of incremental population dose increases is from ≤0.01 to 0.2 person-rem/year and/or 0.002% to 0.46% of the total accident dose. The total doses for the spectrum of all accidents (NUREG-1493 [Reference 6], Figure 7-2) result in health effects that are at least two orders of magnitude less than the NRC Safety Goal Risk. Given these perspectives, a very small population dose is defined as an increase from the baseline interval (3 tests per 10 years) dose of ≤1.0 person-rem per year or 1% of the total baseline dose, whichever is less restrictive for the risk impact assessment of the proposed extended ILRT interval.

3.0 REFERENCES

The following references were used in this calculation:

1. *Revision 3-A to Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, NEI 94-01, July 2012.
2. *Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals*, EPRI, Palo Alto, CA EPRI TR-104285, August 1994.
3. *Interim Guidance for Performing Risk Impact Assessments in Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals*, Revision 4, developed for NEI by EPRI and Data Systems and Solutions, November 2001.
4. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Regulatory Guide 1.174, May 2011.
5. *Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension*, Letter from Mr. C. H. Cruse (Calvert Cliffs Nuclear Power Plant) to NRC Document Control Desk, Docket No. 50-317, March 27, 2002.
6. Performance-Based Containment Leak-Test Program, NUREG-1493, September 1995.
7. *Evaluation of Severe Accident Risks: Methodology for the Containment, Source Term, Consequence, and Risk Integration Analyses*, NUREG/CR-4551, SAND86-1309, Volume 4, Revision 1, Part 1, December 1990.
8. Letter from R. J. Barrett (Entergy) to U. S. Nuclear Regulatory Commission, IPN-01-007, January 18, 2001.
9. United States Nuclear Regulatory Commission, Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment Re: Frequency of Performance-Based Leakage Rate Testing (TAC No. MB0178), April 17, 2001.
10. *Impact of Containment Building Leakage on LWR Accident Risk*, Oak Ridge National Laboratory, NUREG/CR-3539, ORNL/TM-8964, April 1984.
11. *Reliability Analysis of Containment Isolation Systems*, Pacific Northwest Laboratory, NUREG/CR-4220, PNL-5432, June 1985.
12. Technical Findings and Regulatory Analysis for Generic Safety Issue II.E.4.3 'Containment Integrity Check', NUREG-1273, April 1988.
13. *Review of Light Water Reactor Regulatory Requirements*, Pacific Northwest Laboratory, NUREG/CR-4330, PNL-5809, Volume 2, June 1986.
14. Shutdown Risk Impact Assessment for Extended Containment Leakage Testing Intervals Utilizing ORAM™, EPRI, Palo Alto, CA, TR-105189, Final Report, May 1995.
15. *Severe Accident Risks: An Assessment for Five U. S. Nuclear Power Plants*, NUREG-1150, December 1990.
16. United States Nuclear Regulatory Commission, Reactor Safety Study, WASH-1400, October 1975.
17. Engineering Report No. JAF-NE-09-00001, Appendix G, Revision 0, James A. FitzPatrick Nuclear Power Plant, "Accident Sequence Quantification," August 2009.

18. Engineering Report No. JAF-NE-09-00001, Appendix L, Revision 0, James A. FitzPatrick Nuclear Power Plant, “Large Early Release Frequency Quantification,” August 2009.
19. James A. FitzPatrick Nuclear Power Plant, License Renewal Application, 2008.
20. Anthony R. Pietrangelo, One-time extensions of containment integrated leak rate test interval – additional information, NEI letter to Administrative Points of Contact, November 30, 2001.
21. Letter from J. A. Hutton (Exelon, Peach Bottom) to U. S. Nuclear Regulatory Commission, Docket No. 50-278, License No. DPR-56, LAR-01-00430, dated May 30, 2001.
22. *Risk Assessment for Joseph M. Farley Nuclear Plant Regarding ILRT (Type A) Extension Request*, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, P0293010002-1929-030602, March 2002.
23. Letter from D. E. Young (Florida Power, Crystal River) to U. S. Nuclear Regulatory Commission, 3F0401-11, dated April 25, 2001.
24. *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*, Revision 2-A of 1009325, EPRI, Palo Alto, CA. 1018243, October 2008.
25. Risk Assessment for Vogtle Electric Generating Plant Regarding the ILRT (Type A) Extension Request, prepared for Southern Nuclear Operating Co. by ERIN Engineering and Research, February 2003.
26. Perspectives Gained from the IPEEE Program, USNRC, NUREG-1742, April 2002.
27. *Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications*, ASME/ANS RA-Sa–2009, February 2009.
28. ML112070867, “Containment Liner Corrosion Operating Experience Summary Technical Letter Report,” U.S. Nuclear Regulatory Commission Office of Nuclear Regulatory Research, August 2011.
29. Technical Letter Report ML112070867, Containment Liner Corrosion Operating Experience Summary, Revision 1, August 2011.
30. Engineering Report No. JAF-RPT-03-00007, Revision 0, James A. FitzPatrick Nuclear Power Plant, “Risk Impact Assessment of Extending Containment Type A Test Interval,” June 2003.
31. Engineering Report No. JAF-NE-09-00001, Revision 0, Appendix J, James A. FitzPatrick Nuclear Power Plant, “Containment Performance Analysis,” August 2009.
32. Calculation No. JAF-CALC-05-00134, Revision 0, James A. FitzPatrick Nuclear Power Plant, “MACCS2 Model for JAFNPP,” December 2005.
33. *Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard*, NEI 05-04, Revision 2, November 2008.
34. Engineering Report No. JAF-RPT-05-00158, Revision 1, James A. FitzPatrick Nuclear Power Plant, “Cost-Benefit Analysis of Severe Accident Mitigation Alternatives,” June 2006.
35. Engineering Report No. JAF-RPT-MISC-02211, Revision 0, James A. FitzPatrick Nuclear Power Plant, “Individual Plant Examination of External Events,” June 1996.

36. Generic Issue 199 (GI-199), ML100270582, September 2010, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants: Safety/Risk Assessment.”

37. JAF Internal Events PRA Model, JAFSTG.caf and JAF2011.rr, Rev 2, 2011.

38. *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities*, Regulatory Guide 1.200, Revision 2, March 2009.

39. NRC Generic Letter 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities -10 CFR 50.54(f), Supplement 4," June 28, 1991.

40. Parkinson, W. J., “EPRI Fire PRA Implementation Guide”, prepared by Science Applications International Corporation for Electric Power Research Institute, EPRI TR-105928, December 1995.

41. Professional Loss Control, Inc., Fire-Induced Vulnerability Evaluation (FIVE) Methodology Plant Screening Guide, EPRI TR-100370, Electric Power Research Institute, Final Report, April 1992.

42. U.S. Nuclear Regulatory Commission, NUREG-1742 “Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program,” Volume 1 & 2, Final Report, April 2002.

43. NRC letter to James A. FitzPatrick Nuclear Power Plant issuing Technical Specification Amendment 234 to implement the requirements of 10 CFR 50, Appendix J, Option B, dated October 4, 1996.

44. Entergy Nuclear Northeast, “James A. FitzPatrick Nuclear Power Plant Updated Final Safety Analysis,” Revision 4, April 2013.

4.0 ASSUMPTIONS AND LIMITATIONS

The following assumptions were used in the calculation:

- The technical adequacy of the JAF PRA is consistent with the requirements of Regulatory Guide 1.200 [Reference 38] as is relevant to this ILRT interval extension, as detailed in Attachment 1.
- The JAF Level 1 and Level 2 internal events PRA models provide representative results.
- It is appropriate to use the JAF internal events PRA model to effectively describe the risk change attributable to the ILRT extension. An extensive sensitivity study is done in Section 5.3.1 to show the effect of including external event models for the ILRT extension. A Seismic PRA [Reference 36] and Fire PRA from the IPEEE [Reference 35] are used for this sensitivity analysis. It is reasonable to assume that the impact from the ILRT extension (with respect to percent increases in population dose) will not substantially differ if detailed analysis of high wind events were to be included in the calculations.
- Accident classes describing radionuclide release end states are defined consistent with EPRI methodology [Reference 2].
- The representative containment leakage for Class 1 sequences is $1L_a$. Class 3 accounts for increased leakage due to Type A inspection failures.
- The representative containment leakage for Class 3a sequences is $10L_a$ based on the previously approved methodology performed for Indian Point Unit 3 [Reference 8, Reference 9].

- The representative containment leakage for Class 3b sequences is $100L_a$ based on the guidance provided in EPRI Report No. 1009325, Revision 2-A (EPRI 1018243) [Reference 24].
- The Class 3b can be very conservatively categorized as LERF based on the previously approved methodology [Reference 8, Reference 9].
- The impact on population doses from containment bypass scenarios is not altered by the proposed ILRT extension, but is accounted for in the EPRI methodology as a separate entry for comparison purposes. Since the containment bypass contribution to population dose is fixed, no changes in the conclusions from this analysis will result from this separate categorization.
- The reduction in ILRT frequency does not impact the reliability of containment isolation valves to close in response to a containment isolation signal.

5.0 METHODOLOGY AND ANALYSIS

5.1 Inputs

This section summarizes the general resources available as input (Section 5.1.1) and the plant specific resources required (Section 5.1.2).

5.1.1 General Resources Available

Various industry studies on containment leakage risk assessment are briefly summarized here:

1. NUREG/CR-3539 [Reference 10]
2. NUREG/CR-4220 [Reference 11]
3. NUREG-1273 [Reference 12]
4. NUREG/CR-4330 [Reference 13]
5. EPRI TR-105189 [Reference 14]
6. NUREG-1493 [Reference 6]
7. EPRI TR-104285 [Reference 2]
8. NUREG-1150 [Reference 15] and NUREG/CR-4551 [Reference 7]
9. NEI Interim Guidance [Reference 3, Reference 20]
10. Calvert Cliffs liner corrosion analysis [Reference 5]
11. EPRI Report No. 1009325, Revision 2-A (EPRI 1018243), Appendix H [Reference 24]

This first study is applicable because it provides one basis for the threshold that could be used in the Level 2 PRA for the size of containment leakage that is considered significant and is to be included in the model. The second study is applicable because it provides a basis of the probability for significant pre-existing containment leakage at the time of a core damage accident. The third study is applicable because it is a subsequent study to NUREG/CR-4220 that undertook a more extensive evaluation of the same database. The fourth study provides an assessment of the impact of different containment leakage rates on plant risk. The fifth study provides an assessment of the impact on shutdown risk from ILRT test interval extension. The sixth study is the NRC's cost-benefit analysis of various alternative approaches regarding extending the test intervals and increasing the allowable leakage rates for containment integrated and local leak rate tests. The seventh study is an EPRI study of the impact of extending ILRT and local leak rate test (LLRT) intervals on at-power public risk. The eighth study provides an ex-plant consequence analysis for a 50-mile radius surrounding a plant that is used as the basis for the consequence analysis of the ILRT interval extension for JAF. The ninth study includes the NEI recommended methodology (promulgated in two letters) for evaluating the risk associated with obtaining a one-time extension of the ILRT interval. The tenth study

addresses the impact of age-related degradation of the containment liners on ILRT evaluations. Finally, the eleventh study builds on the previous work and includes a recommended methodology and template for evaluating the risk associated with a permanent 15-year extension of the ILRT interval.

NUREG/CR-3539 [Reference 10]

Oak Ridge National Laboratory documented a study of the impact of containment leak rates on public risk in NUREG/CR-3539. This study uses information from WASH-1400 [Reference 16] as the basis for its risk sensitivity calculations. ORNL concluded that the impact of leakage rates on LWR accident risks is relatively small.

NUREG/CR-4220 [Reference 11]

NUREG/CR-4220 is a study performed by Pacific Northwest Laboratories for the NRC in 1985. The study reviewed over two thousand LERs, ILRT reports and other related records to calculate the unavailability of containment due to leakage.

NUREG-1273 [Reference 12]

A subsequent NRC study, NUREG-1273, performed a more extensive evaluation of the NUREG/CR-4220 database. This assessment noted that about one-third of the reported events were leakages that were immediately detected and corrected. In addition, this study noted that local leak rate tests can detect “essentially all potential degradations” of the containment isolation system.

NUREG/CR-4330 [Reference 13]

NUREG/CR-4330 is a study that examined the risk impacts associated with increasing the allowable containment leakage rates. The details of this report have no direct impact on the modeling approach of the ILRT test interval extension, as NUREG/CR-4330 focuses on leakage rate and the ILRT test interval extension study focuses on the frequency of testing intervals. However, the general conclusions of NUREG/CR-4330 are consistent with NUREG/CR-3539 and other similar containment leakage risk studies:

“…the effect of containment leakage on overall accident risk is small since risk is dominated by accident sequences that result in failure or bypass of containment.”

EPRI TR-105189 [Reference 14]

The EPRI study TR-105189 is useful to the ILRT test interval extension risk assessment because it provides insight regarding the impact of containment testing on shutdown risk. This study contains a quantitative evaluation (using the EPRI ORAM software) for two reference plants (a BWR-4 and a PWR) of the impact of extending ILRT and LLRT test intervals on shutdown risk. The conclusion from the study is that a small, but measurable, safety benefit is realized from extending the test intervals.

NUREG-1493 [Reference 6]

NUREG-1493 is the NRC’s cost-benefit analysis for proposed alternatives to reduce containment leakage testing intervals and/or relax allowable leakage rates. The NRC conclusions are consistent with other similar containment leakage risk studies:

Reduction in ILRT frequency from 3 per 10 years to 1 per 20 years results in an “imperceptible” increase in risk.

Given the insensitivity of risk to the containment leak rate and the small fraction of leak paths detected solely by Type A testing, increasing the interval between integrated leak rate tests is possible with minimal impact on public risk.

EPRI TR-104285 [Reference 2]

Extending the risk assessment impact beyond shutdown (the earlier EPRI TR-105189 study), the EPRI TR-104285 study is a quantitative evaluation of the impact of extending ILRT and LLRT test intervals on at-power public risk. This study combined IPE Level 2 models with NUREG-1150 Level 3 population dose models to perform the analysis. The study also used the approach of NUREG-1493 in calculating the increase in pre-existing leakage probability due to extending the ILRT and LLRT test intervals.

EPRI TR-104285 uses a simplified Containment Event Tree to subdivide representative core damage frequencies into eight classes of containment response to a core damage accident:

1. Containment intact and isolated
2. Containment isolation failures dependent upon the core damage accident
3. Type A (ILRT) related containment isolation failures
4. Type B (LLRT) related containment isolation failures
5. Type C (LLRT) related containment isolation failures
6. Other penetration related containment isolation failures
7. Containment failures due to core damage accident phenomena
8. Containment bypass

Consistent with the other containment leakage risk assessment studies, this study concluded:

"…the proposed CLRT (Containment Leak Rate Tests) frequency changes would have a minimal safety impact. The change in risk determined by the analyses is small in both absolute and relative terms. For example, for the PWR analyzed, the change is about 0.04 person-rem per year…"

NUREG-1150 [Reference 15] and NUREG/CR-4551 [Reference 7]

NUREG-1150 and the technical basis, NUREG/CR-4551, provide an ex-plant consequence analysis for a spectrum of accidents including a severe accident with the containment remaining intact (i.e., Tech Spec Leakage). This ex-plant consequence analysis is calculated for the 50-mile radial area surrounding Peach Bottom. The ex-plant calculation can be delineated to total person-rem for each identified Accident Progression Bin (APB) from NUREG/CR-4551. With the JAF Level 2 model end-states assigned to one of the NUREG/CR-4551 APBs, it is considered adequate to represent JAF. (The meteorology and site differences other than population are assumed not to play a significant role in this evaluation.)

NEI Interim Guidance for Performing Risk Impact Assessments In Support of One-Time Extensions for Containment Integrated Leakage Rate Test Surveillance Intervals [Reference 3, Reference 20]

The guidance provided in this document builds on the EPRI risk impact assessment methodology [Reference 2] and the NRC performance-based containment leakage test program [Reference 6], and considers approaches utilized in various submittals, including Indian Point 3 (and associated NRC SER) and Crystal River.

Calvert Cliffs Response to Request for Additional Information Concerning the License Amendment for a One-Time Integrated Leakage Rate Test Extension [Reference 5]

This submittal to the NRC describes a method for determining the change in likelihood, due to extending the ILRT, of detecting liner corrosion, and the corresponding change in risk. The methodology was developed for Calvert Cliffs in response to a request for additional information regarding how the potential leakage due to age-related degradation mechanisms was factored into the risk assessment for the ILRT one-time extension. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner.

EPRI Report No. 1009325, Revision 2-A, Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals [Reference 24]

This report provides a generally applicable assessment of the risk involved in extension of ILRT test intervals to permanent 15-year intervals. Appendix H of this document provides guidance for performing plant-specific supplemental risk impact assessments and builds on the previous EPRI risk impact assessment methodology [Reference 2] and the NRC performance-based containment leakage test program [Reference 6], and considers approaches utilized in various submittals, including Indian Point 3 (and associated NRC SER) and Crystal River.

The approach included in this guidance document is used in the JAF assessment to determine the estimated increase in risk associated with the ILRT extension. This document includes the bases for the values assigned in determining the probability of leakage for the EPRI Class 3a and 3b scenarios in this analysis, as described in Section 5.2.

5.1.2 Plant Specific Inputs

The plant-specific information used to perform the JAF ILRT Extension Risk Assessment includes the following:

- Level 1 Model results [Reference 37]
- Level 2 Model results [Reference 37, Reference 18, Reference 19, Reference 34]
- Release category definitions used in the Level 2 Model [Reference 18, Reference 19, Reference 34]
- Dose within a 50-mile radius [Reference 19, Reference 32]
- ILRT results to demonstrate adequacy of the administrative and hardware issues [Reference 30]
- Containment failure probability data [Reference 31]

JAF Model

The Internal Events PRA Model that is used for JAF is characteristic of the as-built plant. The current Level 2 model (JAF PRA Model JAFSTG, which was updated in 2011) [Reference 37] is a linked fault tree model (with supporting information in Reference 17). The total CDF is 2.40E-6/year.

For the purposes of the ILRT extension analysis, the Level 2 model is used to facilitate mapping the JAF PRA results to the EPRI Accident Classes. Thus, each Level 2 release state top gate was quantified and the resulting cutsets combined to produce a single Level 2 PRA cutset file. When each Level 2 top gate is quantified and the cutsets combined, the total CDF is 2.63E-6/year, which is slightly larger than the single top model total CDF. This slight difference is expected when quantifying separate tops and combining cutsets when compared to a single top quantification. Using the combined Level 2 results of this analysis is conservative with respect to the ILRT extension application. Table 5-1 and Table 5-2 provide a summary of the Internal Events CDF and LERF results for the JAF PRA Model when quantified using the Level 2 model top gates. The total LERF is 2.69E-7/year.

The Fire CDF from the IPEEE [Reference 35] is 2.12E-5/year. The Seismic PRA results from Generic Issue 199 yields a CDF of 6.1E-6/year [Reference 36]. Refer to Section 5.3.1 for further details on external events as they pertain to this analysis.

Table 5-1 – Internal Events CDF

Internal Events	Frequency (per year)
Loss of AC Bus	6.15E-07
Loss of Offsite Power	2.35E-07
Transient	1.20E-06
Loss of DC Bus	2.58E-07
LOCA	1.62E-07
Internal Flooding	1.32E-07
Interfacing Systems LOCA	9.64E-09
LOCA Outside Containment	1.78E-08
Total Internal Events CDF	2.63E-06

Table 5-2 – Internal Events LERF

Internal Events	Frequency (per year)
Loss of AC Bus	3.20E-09
Loss of Offsite Power	2.76E-08
Transient	1.94E-07
Loss of DC Bus	1.24E-08
LOCA	9.08E-09
Internal Flooding	2.91E-09
Interfacing Systems LOCA	9.64E-09
LOCA Outside Containment	1.09E-08
Total Internal Events LERF	2.69E-07

Release Category Definitions

Table 5-3 defines the accident classes used in the ILRT extension evaluation, which is consistent with the EPRI methodology [Reference 2]. These containment failure classifications are used in this analysis to determine the risk impact of extending the Containment Type A test interval, as described in Section 5.2 of this report.

Table 5-3 – EPRI Containment Failure Classification [Reference 2]

Class	Description
1	Containment remains intact including accident sequences that do not lead to containment failure in the long term. The release of fission products (and attendant consequences) is determined by the maximum allowable leakage rate values L_a, under Appendix J for that plant.
2	Containment isolation failures (as reported in the Individual Plant Examinations) including those accidents in which there is a failure to isolate the containment.
3	Independent (or random) isolation failures include those accidents in which the pre-existing isolation failure to seal (i.e., provide a leak-tight containment) is not dependent on the sequence in progress.
4	Independent (or random) isolation failures include those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress. This class is similar to Class 3 isolation failures, but is applicable to sequences involving Type B tests and their potential failures. These are the Type B-tested components that have isolated, but exhibit excessive leakage.
5	Independent (or random) isolation failures including those accidents in which the pre-existing isolation failure to seal is not dependent on the sequence in progress. This class is similar to Class 4 isolation failures, but is applicable to sequences involving Type C test and their potential failures.
6	Containment isolation failures including those leak paths covered in the plant test and maintenance requirements or verified per in-service inspection and testing (ISI/IST) program.
7	Accidents involving containment failure induced by severe accident phenomena. Changes in Appendix J testing requirements do not impact these accidents.
8	Accidents in which the containment is bypassed (either as an initial condition or induced by phenomena) are included in Class 8. Changes in Appendix J testing requirements do not impact these accidents.

5.1.3 Impact of Extension on Detection of Component Failures that Lead to Leakage (Small and Large)

The ILRT can detect a number of component failures such as liner breach, failure of certain bellows arrangements, and failure of some sealing surfaces, which can lead to leakage. The proposed ILRT test interval extension may influence the conditional probability of detecting these types of failures. To ensure that this effect is properly addressed, the EPRI Class 3 accident class, as defined in Table 5-3, is divided into two sub-classes, Class 3a and Class 3b, representing small and large leakage failures respectively.

The probability of the EPRI Class 3a and Class 3b failures is determined consistent with the EPRI Guidance [Reference 24]. For Class 3a, the probability is based on the maximum likelihood estimate of failure (arithmetic average) from the available data (i.e., 2 “small” failures in 217 tests leads to “large” failures in 217 tests (i.e., 2 / 217 = 0.0092). For Class 3b, the probability is based on the Jeffreys non-informative prior (i.e., 0.5 / 218 = 0.0023).

In a follow-up letter [Reference 20] to their ILRT guidance document [Reference 3], NEI issued additional information concerning the potential that the calculated ΔLERF values for several plants may fall above the “very small change” guidelines of the NRC Regulatory Guide 1.174 [Reference 4]. This additional NEI information includes a discussion of conservatisms in the quantitative guidance for ΔLERF. NEI describes ways to demonstrate that, using plant-specific calculations, the ΔLERF is smaller than that calculated by the simplified method.

The supplemental information states:
The methodology employed for determining LERF (Class 3b frequency) involves conservatively multiplying the CDF by the failure probability for this class (3b) of accident. This was done for simplicity and to maintain conservatism. However, some plant-specific accident classes leading to core damage are likely to include individual sequences that either may already (independently) cause a LERF or could never cause a LERF, and are thus not associated with a

postulated large Type A containment leakage path (LERF). These contributors can be removed from Class 3b in the evaluation of LERF by multiplying the Class 3b probability by only that portion of CDF that may be impacted by Type A leakage.

The application of this additional guidance to the analysis for JAF, as detailed in Section 5.2, involves the following:

- The LERF sequences, which includes Class 8 sequences, are subtracted from the CDF that is applied to Class 3b. To be consistent, the same change is made to the Class 3a CDF, even though these events are not considered LERF. Class 2 events refer to sequences with large pre-existing containment isolation failures; Class 8 events refer to sequences with containment bypass events. These sequences are already considered to contribute to LERF in the JAF Level 2 PRA analysis.

Consistent with the NEI Guidance [Reference 3], the change in the leak detection probability can be estimated by comparing the average time that a leak could exist without detection. For example, the average time that a leak could go undetected with a three-year test interval is 1.5 years (3 years / 2), and the average time that a leak could exist without detection for a ten-year interval is 5 years (10 years / 2). This change would lead to a non-detection probability that is a factor of 3.33 (5.0/1.5) higher for the probability of a leak that is detectable only by ILRT testing. Correspondingly, an extension of the ILRT interval to 15 years can be estimated to lead to a factor of 5 ((15/2)/1.5) increase in the non-detection probability of a leak.

It should be noted that using the methodology discussed above is very conservative compared to previous submittals (e.g., the IP3 request for a one-time ILRT extension that was approved by the NRC [Reference 9]) because it does not factor in the possibility that the failures could be detected by other tests (e.g., the Type B local leak rate tests that will still occur). Eliminating this possibility conservatively over-estimates the factor increases attributable to the ILRT extension.

5.2 Analysis

The application of the approach based on the guidance contained in EPRI Report No. 1009325, Revision 2-A, Appendix H [Reference 24], EPRI TR-104285 [Reference 2] and previous risk assessment submittals on this subject [References 5, 8, 21, 22, and 23] have led to the following results. The results are displayed according to the eight accident classes defined in the EPRI report, as described in Table 5-4.

The analysis performed examined JAF-specific accident sequences in which the containment remains intact or the containment is impaired. Specifically, the breakdown of the severe accidents, contributing to risk, was considered in the following manner:

- Core damage sequences in which the containment remains intact initially and in the long term (EPRI TR-104285, Class 1 sequences [Reference 2]).
- Core damage sequences in which containment integrity is impaired due to random isolation failures of plant components other than those associated with Type B or Type C test components. For example, liner breach or bellow leakage (EPRI TR-104285, Class 3 sequences [Reference 2]).
- Accident sequences involving containment bypassed (EPRI TR-104285, Class 8 sequences [Reference 2]), large containment isolation failures (EPRI TR-104285, Class 2 sequences [Reference 2]), and small containment isolation “failure-to-seal” events (EPRI TR-104285, Class 4 and 5 sequences [Reference 2]) are accounted for in this evaluation as part of the baseline risk profile. However, they are not affected by the ILRT frequency change.

- Class 4 and 5 sequences are impacted by changes in Type B and C test intervals; therefore, changes in the Type A test interval do not impact these sequences.

Table 5-4 – EPRI Accident Class Definitions

Accident Classes (Containment Release Type)	Description
1	No Containment Failure
2	Large Isolation Failures (Failure to Close)
3a	Small Isolation Failures (Liner Breach)
3b	Large Isolation Failures (Liner Breach)
4	Small Isolation Failures (Failure to Seal – Type B)
5	Small Isolation Failures (Failure to Seal – Type C)
6	Other Isolation Failures (e.g., Dependent Failures)
7a	Failures Induced by Phenomena (Early)
7b	Failures Induced by Phenomena (Late)
8	Bypass (Interfacing System LOCA)
CDF	All CET End States (Including Very Low and No Release)

The steps taken to perform this risk assessment evaluation are as follows:

Step 1 - Quantify the baseline risk in terms of frequency per reactor year for each of the accident classes presented in Table 5-4.

Step 2 - Develop plant-specific person-rem dose (population dose) per reactor year for each of the eight accident classes.

Step 3 - Evaluate risk impact of extending Type A test interval from 3 in 10 years to 1 in 15 years and 1 in 10 years to 1 in 15 years.

Step 4 - Determine the change in risk in terms of Large Early Release Frequency (LERF) in accordance with RG 1.174 [Reference 4].

Step 5 - Determine the impact on the Conditional Containment Failure Probability (CCFP).

5.2.1 Step 1 – Quantify the Baseline Risk in Terms of Frequency per Reactor Year

As previously described, the extension of the Type A interval does not influence those accident progressions that involve large containment isolation failures, Type B or Type C testing, or containment failure induced by severe accident phenomena.

For the assessment of ILRT impacts on the risk profile, the potential for pre-existing leaks is included in the model. (These events are represented by the Class 3 sequences in EPRI TR-104285 [Reference 2].) The question on containment integrity was modified to include the probability of a liner breach or bellows failure (due to excessive leakage) at the time of core damage. Two failure modes were considered for the Class 3 sequences. These are Class 3a (small breach) and Class 3b (large breach).

The frequencies for the severe accident classes defined in Table 5-4 were developed for JAF by first determining the frequencies for Classes 1, 2, 6, 7, and 8. Table 5-5 presents the grouping of each release category in EPRI Classes based on the associated description. Table 5-6 presents the release categories, frequency, and EPRI category for each sequence and the totals of each EPRI classification. Table 5-7 provides a summary of the accident sequence frequencies that can lead to radionuclide release to the public and have been derived consistent

with the definitions of accident classes defined in EPRI TR-104285 [Reference 2], the NEI Interim Guidance [Reference 3], and guidance provided in EPRI Report No. 1009325, Revision 2-A [Reference 24]. Adjustments were made to the Class 3b and hence Class 1 frequencies to account for the impact of undetected corrosion of the steel liner per the methodology described in Section 5.2.6. Note: calculations were performed with more digits than shown in this section. Therefore, minor differences may occur if the calculations in these sections are followed explicitly.

Class 3 Sequences. This group consists of all core damage accident progression bins for which a pre-existing leakage in the containment structure (e.g., containment liner) exists that can only be detected by performing a Type A ILRT. The probability of leakage detectable by a Type A ILRT is calculated to determine the impact of extending the testing interval. The Class 3 calculation is divided into two classes: Class 3a is defined as a small liner breach (L_a < leakage < $10L_a$), and Class 3b is defined as a large liner breach ($10L_a$ < leakage < $100L_a$).

Data reported in EPRI 1009325, Revision 2-A [Reference 24] states that two events could have been detected only during the performance of an ILRT and thus impact risk due to change in ILRT frequency. There were a total of 217 successful ILRTs during this data collection period. Therefore, the probability of leakage is determined for Class 3a as shown in the following equation:

$$P_{class3a} = \frac{2}{217} = 0.0092$$

Multiplying the CDF by the probability of a Class 3a leak yields the Class 3a frequency contribution in accordance with guidance provided in Reference 24. As described in Section 5.1.3, additional consideration is made to not apply failure probabilities on those cases that are already LERF scenarios. Therefore, these LERF contributions from CDF are removed. Therefore, the frequency of a Class 3a failure is calculated by the following equation:

$$Freq_{class3a} = P_{class3a} * (CDF - LERF) = \frac{2}{217} * (2.63\text{E-}6 - 2.69\text{E-}7) = 2.18\text{E-}8$$

In the database of 217 ILRTs, there are zero containment leakage events that could result in a large early release. Therefore, the Jeffreys non-informative prior is used to estimate a failure rate and is illustrated in the following equations:

$$\text{Jeffreys Failure Probability} = \frac{Number\ of\ Failures + 1/2}{Number\ of\ Tests + 1}$$

$$P_{class3b} = \frac{0 + 1/2}{217 + 1} = 0.0023$$

The frequency of a Class 3b failure is calculated by the following equation:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{.5}{218} * (2.63\text{E-}6 - 2.69\text{E-}7) = 5.43\text{E-}9$$

For this analysis, the associated containment leakage for Class 3a is $10L_a$ and for Class 3b is $100L_a$. These assignments are consistent with the guidance provided in Reference 24.

Class 1 Sequences. This group consists of all core damage accident progression bins for which the containment remains intact (modeled as Technical Specification Leakage). The frequency per year is initially determined from the EPRI Accident Class 1 frequency listed in Table 5-6 and then subtracting the EPRI Class 3a and 3b frequency (to preserve total CDF), calculated below:

$$Freq_{class1} = Freq_{class1} - (Freq_{class3a} + Freq_{class3b})$$

Class 2 Sequences. This group consists of core damage accident progression bins with large containment isolation failures. The frequency per year for these sequences is obtained from the

EPRI Accident Class 2 frequency listed in Table 5-6.

Class 4 Sequences. This group consists of all core damage accident progression bins for which containment isolation failure-to-seal of Type B test components occurs. Because these failures are detected by Type B tests which are unaffected by the Type A ILRT, this group is not evaluated any further in the analysis, consistent with approved methodology.

Class 5 Sequences. This group consists of all core damage accident progression bins for which a containment isolation failure-to-seal of Type C test components occurs. Because the failures are detected by Type C tests which are unaffected by the Type A ILRT, this group is not evaluated any further in this analysis, consistent with approved methodology.

Class 6 Sequences. These are sequences that involve core damage accident progression bins for which a failure-to-seal containment leakage due to failure to isolate the containment occurs. These sequences are dominated by misalignment of containment isolation valves following a test/maintenance evolution. All other failure modes are bounded by the Class 2 assumptions. This accident class is also not evaluated further.

Class 7 Sequences. This group consists of all core damage accident progression bins in which containment failure is induced by severe accident phenomena (e.g., overpressure). The Level 2 model defines early releases as happening before 6 hours, intermediate releases as happening between 6 and 24 hours, and late releases as happening after 24 hours [Reference 31]. The Level 3 model calculates population dose for early (less than 24 hours) and late (greater than 24 hours) releases [Reference 32]. Therefore, all early and intermediate releases from the Level 2 quantification are grouped into the early group for multiplication with the early population dose in this calculation. This class is split into early (7a) and late (7b) failures. For this analysis, the frequency is determined from the EPRI Accident Class 7 frequencies listed in Table 5-6.

Class 8 Sequences. This group consists of all core damage accident progression bins in which containment bypass occurs, which includes interfacing system LOCAs (ISLOCAs) and LOCAs outside containment (LOCAOC). For this analysis, the frequency is determined from the EPRI Accident Class 8 frequency listed in Table 5-6.

Level 2 quantification of the 2011 JAFSTG model [Reference 37] is distributed into EPRI classes based on release categories. Table 5-5 shows this distribution.

Table 5-5 – Release Category Frequencies

Release Category	Description of Outcome	EPRI Category	Frequency (/yr)
NCF	No Containment Failure	1	5.86E-07
CIS	Containment Isolation Failure	2	3.31E-09
LERF (no bypass)	Large Early Release Frequency (excluding containment bypass)	7a	2.49E-07
MERF	Medium Early Release Frequency	7a	3.35E-08
SERF	Small Early Release Frequency	7a	3.42E-08
SSERF	Small-Small Early Release Frequency	7a	0.00E+00
LIRF	Large Intermediate Release Frequency	7a	0.00E+00
MIRF	Medium Intermediate Release Frequency	7a	0.00E+00
SIRF	Small Intermediate Release Frequency	7a	1.40E-07
SSIRF	Small-Small Intermediate Release Frequency	7a	8.16E-08
LLRF	Large Late Release Frequency	7b	1.20E-06
MLRF	Medium Late Release Frequency	7b	6.34E-08
SLRF	Small Late Release Frequency	7b	2.22E-07
SSLRF	Small-Small Late Release Frequency	7b	0.00E+00
ISLOCA	Interfacing Systems LOCA	8	9.64E-09
LOCAOC	LOCA Outside Containment (that leads to LERF)	8	1.09E-08

Table 5-5 – Release Category Frequencies

Release Category	Description of Outcome	EPRI Category	Frequency (/yr)
	Contribution to EPRI Classification 2		3.31E-09
	Contribution to EPRI Classification 7a		5.39E-07
	Contribution to EPRI Classification 7b		1.49E-06
	Contribution to EPRI Classification 8		2.05E-08

Table 5-6 – Accident Class Frequencies

Release Categories	EPRI Category	Frequency (/yr)
NCF	Class 1	5.86E-07
CIS	Class 2	3.31E-09
EARLY	Class 7a	5.39E-07
LATE	Class 7b	1.49E-06
ISLOCA, LOCAOC	Class 8	2.05E-08
Total (CDF)	N/A	2.63E-06

Table 5-7 – Baseline Risk Profile

Class	Description	Frequency (/yr)
1	No containment failure	5.58E-07[2]
2	Large containment isolation failures	3.31E-09
3a	Small isolation failures (liner breach)	2.18E-08
3b	Large isolation failures (liner breach)	5.43E-09
4	Small isolation failures - failure to seal (Type B)	ε[1]
5	Small isolation failures - failure to seal (Type C)	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]
7a	Severe accident phenomena induced failure (early)	5.39E-07
7b	Severe accident phenomena induced failure (late)	1.49E-06
8	Containment bypass	2.05E-08
	Total	2.63E-06

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 3a and 3b frequencies are subtracted from Class 1 to preserve total CDF.

5.2.2 Step 2 – Develop Plant-Specific Person-Rem Dose (Population Dose)

Plant-specific release analyses were performed to estimate the person-rem doses to the population within a 50-mile radius from the plant. Reference 19 provides the population dose for Classes 7a and 7b. The population dose for Classes 1, 2, and 8 are calculated using the methodology of scaling Peach Bottom population doses to JAF [Reference 7]. Reference 19 also provides dose information for no containment failure, but scaling the Peach Bottom population doses to JAF produces a more conservative value; therefore, the scaled value is used in this analysis. The adjustment factor for reactor power level (AF_{power}) is defined as the ratio of the power level at JAF (PLF) [Reference 44] to that at Peach Bottom Unit 2 (PLP) [Reference 7]. This adjustment factor is calculated as follows:

$AF_{power} = PLF / PLP = 2536 / 3293 = 0.770$

The adjustment factor for technical specification (TS) allowed containment leakage is defined as the ratio of the containment leakage at FitzPatrick (LRF) to that at Peach Bottom Unit 2 (LRP). This adjustment factor is calculated as follows:

$AF_{leakage} = LRF / LRP$

Since the leakage rates are in terms of the containment volume, the ratio of containment volumes is needed to relate the leakage rates. The TS maximum allowed containment leakage at JAF (TS_{JAF}) is 1.5 volume%/day [Reference 43]; the containment free volume at JAF (VOL_{JAF}) is 264,000 ft^3 [Table 5.2-1 of Reference 44]. The TS maximum allowed containment leakage at Peach Bottom Unit 2 (TS_{PB}) is 0.5 volume%/day [Reference 7]; the containment free volume at Peach Bottom Unit 2 (VOL_{PB}) is 307,000 ft^3 [Reference 7].Therefore,

$LRF = TS_{JAF} * VOL_{JAF}$

$LRP = TS_{PB} * VOL_{PB}$

$AF_{leakage} = (1.5 * 264000) / (0.5 * 307000) = 2.58$

The adjustment factor for population ($AF_{Population}$) is defined as the ratio of the population within 50-mile radius of JAF (POPF) [Reference 19] to that of Peach Bottom Unit 2 (POPP) [Reference 7]. According to the 2000 census, the population within 50 miles of JAF was 914,668 and is projected to decline by approximately 6% over the remaining life of the power plant [Reference 19]. Therefore, the 2000 census population is used as a slightly conservative value. This adjustment factor is calculated as follows:

$AF_{Population} = POPF / POPP = 914668 / 3.02E{+}6 = 0.303$

Consequences dependent on the INTACT TS Leakage (collapsed accident progression bins 8 and 10).

$AF_{INTACT} = AF_{power} * AF_{Leakage} * AF_{Population} = 0.770 * 2.58 * 0.303 = 0.602$

Since the other categories are not dependent on the TS Leakage, the adjustment factor (AF) is calculated by combining the factors as follows:

$AF = AF_{power} * AF_{Population} = 0.770 * 0.303 = 0.233$

The population dose data in NUREG/CR-4551 for Peach Bottom Unit 2 [Reference 7] is reported in ten distinct collapsed accident progression bins (CAPBs). For this ILRT extension application, CAPB8 and CAPB10 are categorized in EPRI Accident Class 1; CAPB3 is categorized in EPRI Accident Class 2; and CAPB7 is categorized in EPRI Accident Class 8. Based on the above adjustment factors and the 50-mile population dose (person-rem) for each CAPB considered in the NUREG/CR-4551 Peach Bottom Unit 2 study, the JAF population doses (JAFPD) for Classes 2 and 8 are calculated as follows:

$JAFPD_{Class1} = AF_{INTACT} * PD_{CAPB8} + AF_{INTACT} * PD_{CAPB10} = 0.602 * 4.94E{+}3 + 0.602 * 0 = 2.97E{+}3$

$JAFPD_{Class2} = AF * PD_{CAPB3} = 0.233 * 2.97E{+}6 = 6.93E{+}5$

$JAFPD_{Class8} = AF * PD_{CAPB7} = 0.233 * 1.95E{+}6 = 4.55E{+}5$

Table 5-8 provides a correlation of JAF population dose to EPRI Accident Class. Table 5-9 provides population dose for each EPRI accident class.

The population dose for EPRI Accident Classes 3a and 3b were calculated based on the guidance provided in EPRI Report No. 1009325, Revision 2-A [Reference 24] as follows:

$$EPRI\ Class\ 3a\ Population\ Dose = 10 * 2.97\mathrm{E}+3 = 2.97E{+}4$$

$$EPRI\ Class\ 3b\ Population\ Dose = 100 * 2.97\mathrm{E}+3 = 2.97E{+}5$$

Table 5-8 – Mapping of Population Dose to EPRI Accident Class

Release Category	EPRI Category	Frequency (/yr)	Population Dose (person-rem)
INTACT	Class 1	5.58E-07	2.97E+03
CIS	Class 2	3.31E-09	6.93E+05
EARLY	Class 7a	5.39E-07	1.28E+06
LATE	Class 7b	1.49E-06	6.81E+05
ISLOCA, LOCAOC	Class 8	2.05E-08	4.55E+05

Table 5-9 – Baseline Population Doses

Class	Description	Population Dose (person-rem)
1	No containment failure	2.97E+03
2	Large containment isolation failures	6.93E+05
3a	Small isolation failures (liner breach)	2.97E+04[1]
3b	Large isolation failures (liner breach)	2.97E+05[2]
4	Small isolation failures - failure to seal (type B)	N/A[3]
5	Small isolation failures - failure to seal (type C)	N/A[3]
6	Containment isolation failures (dependent failure, personnel errors)	N/A[3]
7a	Severe accident phenomena induced failure (early)	1.28E+06
7b	Severe accident phenomena induced failure (late)	6.81E+05
8	Containment bypass	4.55E+05

1. $10*L_a$
2. $100*L_a$
3. The reason for the “N/A” is explained in Section 5.2.1.

5.2.3 Step 3 – Evaluate Risk Impact of Extending Type A Test Interval from 10 to 15 Years

The next step is to evaluate the risk impact of extending the test interval from its current 10-year interval to a 15-year interval. To do this, an evaluation must first be made of the risk associated with the 10-year interval, since the base case applies to 3-year interval (i.e., a simplified representation of a 3-to-10 interval).

<u>Risk Impact Due to 10-Year Test Interval</u>

As previously stated, Type A tests impact only Class 3 sequences. For Class 3 sequences, the release magnitude is not impacted by the change in test interval (a small or large breach remains the same, even though the probability of not detecting the breach increases). Thus, only the frequency of Class 3a and Class 3b sequences is impacted. The risk contribution is changed based on the NEI guidance as described in Section 5.1.3 by a factor of 10/3 compared to the base case values. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF) = \frac{10}{3} * \frac{2}{217} * 2.37\text{E-}6 = 7.27\text{E-}8$$

$$Freq_{Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF) = \frac{10}{3} * \frac{.5}{218} * 2.37\text{E-}6 = 1.81\text{E-}8$$

The results of the calculation for a 10-year interval are presented in Table 5-10.

Table 5-10 – Risk Profile for Once in 10 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	4.95E-07	18.78%	2.97E+03	1.47E-03
2	Large containment isolation failures	3.31E-09	0.13%	6.93E+05	2.29E-03
3a	Small isolation failures (liner breach)	7.27E-08	2.76%	2.97E+04	2.16E-03
3b	Large isolation failures (liner breach)	1.81E-08	0.69%	2.97E+05	5.37E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7a	Severe accident phenomena induced failure (early)	5.39E-07	20.44%	1.28E+06	6.87E-01
7b	Severe accident phenomena induced failure (late)	1.49E-06	56.43%	6.81E+05	1.01E+00
8	Containment bypass	2.05E-08	0.78%	4.55E+05	9.33E-03
	Total	2.63E-06			1.72E+00

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

<u>Risk Impact Due to 15-Year Test Interval</u>

The risk contribution for a 15-year interval is calculated in a manner similar to the 10-year interval. The difference is in the increase in probability of leakage in Classes 3a and 3b. For this case, the value used in the analysis is a factor of 5 compared to the 3-year interval value, as described in Section 5.1.3. The Class 3a and 3b frequencies are calculated as follows:

$$Freq_{Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF) = 5 * \frac{2}{217} * 2.37\text{E-}6 = 1.09\text{E-}7$$

$$Freq_{Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF) = 5 * \frac{.5}{218} * 2.37\text{E-}6 = 2.71\text{E-}8$$

The results of the calculation for a 15-year interval are presented in Table 5-11.

Table 5-11 – Risk Profile for Once in 15 Year ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	4.50E-07	17.06%	2.97E+03	1.34E-03
2	Large containment isolation failures	3.31E-09	0.13%	6.93E+05	2.29E-03
3a	Small isolation failures (liner breach)	1.09E-07	4.14%	2.97E+04	3.24E-03
3b	Large isolation failures (liner breach)	2.71E-08	1.03%	2.97E+05	8.06E-03
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]	ε[1]	ε[1]
7a	Severe accident phenomena induced failure (early)	5.39E-07	20.44%	1.28E+06	6.87E-01
7b	Severe accident phenomena induced failure (late)	1.49E-06	56.43%	6.81E+05	1.01E+00
8	Containment bypass	2.05E-08	0.78%	4.55E+05	9.33E-03
	Total	2.63E-06			1.72E+00

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 1 frequency is reduced by the frequency of Class 3a and Class 3b in order to preserve total CDF.

5.2.4 Step 4 – Determine the Change in Risk in Terms of LERF and Dose

The risk increase associated with extending the ILRT interval involves the potential that a core damage event that normally would result in only a small radioactive release from an intact containment could, in fact, result in a larger release due to the increase in probability of failure to detect a pre-existing leak. With strict adherence to the EPRI guidance, 100% of the Class 3b contribution would be considered LERF.

Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 [Reference 4] defines very small changes in risk as resulting in increases of CDF less than 10^{-6}/year and increases in LERF less than 10^{-7}/year, and small changes in LERF as less than 10^{-6}/year. Since containment overpressure is not required in support of ECCS performance to mitigate design basis accidents at JAF, the ILRT extension does not impact CDF. Therefore, the relevant risk-impact metric is LERF.

For JAF, 100% of the frequency of Class 3b sequences can be used as a very conservative first-order estimate to approximate the potential increase in LERF from the ILRT interval extension (consistent with the EPRI guidance methodology). Based on a 3-in-10-year test interval from Table 5-8, the Class 3b frequency is 5.43E-9; based on a 10-year test interval from Table 5-10, the Class 3b frequency is 1.81E-8/year; based on a 15-year test interval from Table 5-11, the Class 3b frequency is 2.71E-8/year. Thus, the increase in LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is 2.17E-8/year.

Similarly, the increase due to increasing the interval from 10 to 15 years is 9.04E-9/year. As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF is less than the threshold criteria for a very small change when comparing the 15-year results to the current 10-year requirement and the original 3-year requirement. Table 5-12 summarizes these results.

Table 5-12 – Impact on LERF due to Extended Type A Testing Intervals

ILRT Inspection Interval	3 Years (baseline)	10 Years	15 Years
Class 3b (Type A LERF)	5.43E-09	1.81E-08	2.71E-08
ΔLERF (3 year baseline)		1.27E-08	2.17E-08
ΔLERF (10 year baseline)			9.04E-09

EPRI Report No. 1009325, Revision 2-A [Reference 24] states that a very small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. As shown in Table 5-13, the results of this calculation meet these criteria.

Table 5-13 – Impact on Dose Rate due to Extended Type A Testing Intervals

ILRT Inspection Interval	10 Years	15 Years
ΔDose Rate (3 year baseline)	5.08E-03	8.71E-03
ΔDose Rate (10 year baseline)		3.63E-03
%ΔDose Rate (3 year baseline)	0.296%	0.508%
%ΔDose Rate (10 year baseline)		0.211%

5.2.5 Step 5 – Determine the Impact on the Conditional Containment Failure Probability

Another parameter that the NRC guidance in RG 1.174 [Reference 4] states can provide input into the decision-making process is the change in the conditional containment failure probability (CCFP). The CCFP is defined as the probability of containment failure given the occurrence of an accident. This probability can be expressed using the following equation:

$$CCFP = 1 - \frac{f(ncf)}{CDF}$$

where *f*(ncf) is the frequency of those sequences that do not result in containment failure; this frequency is determined by summing the Class 1 and Class 3a results.

Table 5-14 shows the steps and results of this calculation. The difference in CCFP between the 3-year test interval and 15-year test interval is 0.824%.

Table 5-14 – Impact on CCFP due to Extended Type A Testing Intervals

ILRT Inspection Interval	3 Years (baseline)	10 Years	15 Years
f(ncf) (/yr)	5.80E-07	5.68E-07	5.59E-07
f(ncf)/CDF	0.220	0.215	0.212
CCFP	0.780	0.785	0.788
ΔCCFP (3 year baseline)		0.480%	0.824%
ΔCCFP (10 year baseline)			0.343%

As stated in Section 2.0, a change in the CCFP of up to 1.5% is assumed to be small. The increase in the CCFP from the 3 in 10 year interval to 1 in 15 year interval is 0.824%. Therefore, this increase is judged to be very small.

5.2.6 Impact of Extension on Detection of Steel Liner Corrosion that Leads to Leakage

An estimate of the likelihood and risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is evaluated using a methodology similar to the Calvert Cliffs liner corrosion analysis [Reference 5]. The Calvert Cliffs analysis was performed for a concrete cylinder and dome and a concrete basemat, each with a steel liner.

The following approach is used to determine the change in likelihood, due to extending the ILRT, of detecting corrosion of the containment steel liner. This likelihood is then used to determine the resulting change in risk. Consistent with the Calvert Cliffs analysis, the following issues are addressed:

- Differences between the containment basemat and the containment cylinder and dome
- The historical steel liner flaw likelihood due to concealed corrosion
- The impact of aging
- The corrosion leakage dependency on containment pressure
- The likelihood that visual inspections will be effective at detecting a flaw

<u>Assumptions</u>

- Based on a review of industry events, an Oyster Creek incident is assumed to be applicable to JAF for a concealed shell failure in the floor. In the Calvert Cliffs analysis, this event was assumed not to be applicable and a half failure was assumed for basemat concealed liner corrosion due to the lack of identified failures (See Table 5-15, Step 1).
- The two corrosion events used to estimate the liner flaw probability in the Calvert Cliffs previous analysis are assumed to still be applicable.
- Consistent with the Calvert Cliffs analysis, the estimated historical flaw probability is also limited to 5.5 years to reflect the years since September 1996 when 10 CFR 50.55a started requiring visual inspection. Additional success data was not used to limit the aging impact of this corrosion issue, even though inspections were being performed prior to this date (and have been performed since the time frame of the Calvert Cliffs analysis) (See Table 5-15, Step 1).
- Consistent with the Calvert Cliffs analysis, the steel liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this analysis to address the increased likelihood of corrosion as the steel liner ages (See Table 5-15, Steps 2 and 3). Sensitivity studies are included that address doubling this rate every ten years and every two years.
- In the Calvert Cliffs analysis, the likelihood of the containment atmosphere reaching the outside atmosphere, given that a liner flaw exists, was estimated as 1.1% for the cylinder and dome, and 0.11% (10% of the cylinder failure probability) for the basemat. These values were determined from an assessment of the probability versus containment pressure. For JAF, the ultimate pressure is 137 psig [Reference 31]. Probabilities of 1% for the cylinder and dome, and 0.1% for the basemat are used in this analysis, and sensitivity studies are included in Section 5.3.2 (See Table 5-15, Step 4).
- Consistent with the Calvert Cliffs analysis, the likelihood of leakage escape (due to crack formation) in the basemat region is considered to be less likely than the containment cylinder and dome region (See Table 5-15, Step 4).

- Consistent with the Calvert Cliffs analysis, a 5% visual inspection detection failure likelihood given the flaw is visible and a total detection failure likelihood of 10% is used. To date, all liner corrosion events have been detected through visual inspection (See Table 5-15, Step 5).
- Consistent with the Calvert Cliffs analysis, all non-detectable containment failures are assumed to result in early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

Table 5-15 – Steel Liner Corrosion Base Case

Step	Description	Containment Cylinder and Dome (85%)	Containment Basemat (15%)
1	Historical liner flaw likelihood Failure data: containment location specific Success data: based on 70 steel-lined containments and 5.5 years since the 10CFR 50.55a requirements of periodic visual inspections of containment surfaces	Events: 2 (Brunswick 2 and North Anna 2) 2 / (70 x 5.5) = 5.19E-03	Events: 1 (Oyster Creek) 1 / (70 x 5.5) = 2.60E-03
2	Aged adjusted liner flaw likelihood During the 15-year interval, assume failure rate doubles every five years (14.9% increase per year). The average for the 5th to 10th year set to the historical failure rate.	Year / Failure rate 1 / 2.05E-03 average 5-10 / 5.19E-03 15 / 1.43E-02 15 year average = 6.44E-03	Year / Failure rate 1 / 1.03E-03 average 5-10 / 2.60E-03 15 / 7.14E-03 15 year average = 3.22E-03
3	Increase in flaw likelihood between 3 and 15 years Uses aged adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years.	0.73% (1 to 3 years) 4.18% (1 to 10 years) 9.66% (1 to 15 years)	0.36% (1 to 3 years) 2.08% (1 to 10 years) 4.82% (1 to 15 years)
4	Likelihood of breach in containment given liner flaw	1%	0.1%
5	Visual inspection detection failure likelihood	10% 5% failure to identify visual flaws plus 5% likelihood that the flaw is not visible (not through-cylinder but could be detected by ILRT). All events have been detected through visual inspection. 5% visible failure detection is a conservative assumption.	100% Cannot be visually inspected
6	Likelihood of non-detected containment leakage (Steps 3 x 4 x 5)	0.00073% (3 years) 0.73% x 1% x 10% 0.00418% (10 years) 4.18% x 1% x 10% 0.00966% (15 years) 9.66% x 1% x 10%	0.000360% (3 years) 0.36% x 0.1% x 100% 0.00208% (10 years) 2.08% x 0.1% x 100% 0.00482% (15 years) 4.82% x 0.1% x 100%

The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome, and the containment basemat, as summarized below for JAF.

Table 5-16 – Total Likelihood on Non-Detected Containment Leakage Due to Corrosion for JAF

Description
At 3 years: 0.00073% + 0.000360% = 0.00109%
At 10 years: 0.00418% + 0.00208% = 0.00626%
At 15 years: 0.00966% + 0.00482% = 0.01448%

The above factors are applied to those core damage accidents that are not already independently LERF or that could never result in LERF.

The two corrosion events that were initiated from the non-visible (backside) portion of the containment liner used to estimate the liner flaw probability in the Calvert Cliffs analysis are assumed to be applicable to this containment analysis. These events, one at North Anna Unit 2 (September 1999) caused by timber embedded in the concrete immediately behind the containment liner, and one at Brunswick Unit 2 (April 1999) caused by a cloth work glove embedded in the concrete next to the liner, were initiated from the nonvisible (backside) portion of the containment liner. A search of the NRC website LER database identified two additional events have occurred since the Calvert Cliffs analysis was performed. In January 2000, a 3/16-inch circular through-liner hole was found at Cook Nuclear Plant Unit 2 caused by a wooden brush handle embedded immediately behind the containment liner. The other event occurred in April 2009, where a through-liner hole approximately 3/8-inch by 1-inch in size was identified in the Beaver Valley Power Station Unit 1 (BVPS-1) containment liner caused by pitting originating from the concrete side due to a piece of wood that was left behind during the original construction that came in contact with the steel liner. Two other containment liner through-wall hole events occurred at Turkey Point Units 3 and 4 in October 2010 and November 2006, respectively. However, these events originated from the visible side caused by the failure of the coating system, which was not designed for periodic immersion service, and are not considered to be applicable to this analysis. More recently, in October 2013, some through-wall containment liner holes were identified at BVPS-1, with a combined total area of approximately 0.395 square inches. The cause of these through-wall liner holes was attributed to corrosion originating from the outside concrete surface due to the presence of rayon fiber foreign material that was left behind during the original construction and was contacting the steel liner [References 28 and 29]. For risk evaluation purposes, these five total corrosion events occurring in 66 operating plants with steel containment liners over a 17.1 year period from September 1996 to October 4, 2013 (i.e., 5/(66*17.1) = 4.43E-03) are bounded by the estimated historical flaw probability based on the two events in the 5.5 year period of the Calvert Cliffs analysis (i.e., 2/(70*5.5) = 5.19E-03) incorporated in the EPRI guidance.

5.3 Sensitivities

5.3.1 Potential Impact from External Events Contribution

An assessment of the impact of external events is performed. The primary purpose for this investigation is the determination of the total LERF following an increase in the ILRT testing interval from 3 in 10 years to 1 in 15 years.

The IPEEE Fire PRA calculated a CDF of 2.12E-5 [Reference 35]. Since no Fire LERF value is calculated, it is reasonable to assume the LERF/CDF ratio will be similar for fire risk as for internal events risk. Applying the internal event LERF/CDF ratio to the Fire CDF yields an estimated Fire LERF of 2.17E-6, as shown by the equation below.

$$\mathrm{LERF_{Fire}} \approx \mathrm{CDF_{Fire}} * \mathrm{LERF_{IE}} \,/\, \mathrm{CDF_{IE}} = 2.12\text{E-}5 * 2.69\text{E-}7 \,/\, 2.63\text{E-}6 = 2.17\text{E-}6$$

To reduce conservatism in the ILRT extension analysis, the methodology of subtracting existing LERF from CDF is also applied to the Fire PRA model. The following shows the calculation for Class 3b:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (2.12E\text{-}5 - 2.17E\text{-}6) = 4.37E\text{-}8$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (2.12E\text{-}5 - 2.17E\text{-}6) = 1.46\text{E-}7$$

$$Freq_{U1class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (2.12E\text{-}5 - 2.17E\text{-}6) = 2.19\text{E-}7$$

The IPEEE Seismic Margin Assessment (SMA) does not result in an estimate of CDF [Reference 35]. The conclusions reached in 2010 by GI-199 [Reference 36] are used for estimating Seismic CDF at plants in the Central and Eastern United States, which includes JAF. The most conservative Seismic CDF reported for JAF in Table D-1 of Reference 36 is 6.1E-6. Applying the internal event LERF/CDF ratio to the Seismic CDF yields an estimated seismic LERF of 6.24E-7, as shown by the equation below.

$$\text{LERF}_{\text{Seismic}} \approx \text{CDF}_{\text{Seismic}} * \text{LERF}_{\text{IE}} / \text{CDF}_{\text{IE}} = 6.1\text{E-}6 * 2.69\text{E-}7 / 2.63\text{E-}6 = 6.24\text{E-}7$$

Again subtracting LERF from CDF, the Class 3b frequency can be calculated by the following formulas:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (6.1\text{E-}6 - 6.24\text{E-}7) = 1.26\text{E-}8$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (6.1\text{E-}6 - 6.24\text{E-}7) = 4.19\text{E-}8$$

$$Freq_{class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = \frac{15}{3} * \frac{0.5}{218} * (6.1\text{E-}6 - 6.24\text{E-}7) = 6.28\text{E-}8$$

The IPEEE [Section 1.4.3 of Reference 35] states, “No risks to the plant occasioned by high winds and tornadoes, external floods, ice, and hazardous chemical, transportation and nearby facility incidents were identified that might lead to core damage with a predicted frequency in excess of 10^{-6}/year.” Therefore, for this sensitivity a conservative CDF of 10^{-6} is used for all other external events. Applying the internal event LERF/CDF ratio to the other external events CDF yields an estimated high wind LERF of 1.02E-7. Again subtracting LERF from CDF, the Class 3b frequency can be calculated by the following formulas:

$$Freq_{class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (1.0\text{E-}6 - 1.02\text{E-}7) = 2.06\text{E-}9$$

$$Freq_{class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (1.0\text{E-}6 - 1.02\text{E-}7) = 6.86\text{E-}9$$

$$Freq_{class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = \frac{15}{3} * \frac{0.5}{218} * (1.0\text{E-}6 - 1.02\text{E-}7) = 1.03\text{E-}8$$

The fire, seismic, and other external events contributions to Class 3b frequencies are then combined to obtain the total external event contribution to Class 3b frequencies. The change in LERF is calculated for the 1 in 10 year and 1 in 15 year cases and the change defined for the external events in Table 5-17.

Table 5-17 – JAF External Event Impact on ILRT LERF Calculation

Hazard	EPRI Accident Class 3b Frequency			LERF Increase (from 3 per 10 years to 1 per 15 years)
	3 per 10 year	1 per 10 year	1 per 15 years	
External Events	5.83E-08	1.94E-07	2.92E-07	2.33E-07
Internal Events	5.43E-09	1.81E-08	2.71E-08	2.17E-08
Combined	6.37E-08	2.12E-07	3.19E-07	2.55E-07

The internal event results are also provided to allow a composite value to be defined. When both the internal and external event contributions are combined, the total change in LERF of 2.55E-7 meets the guidance for small change in risk, as it exceeds 1.0E-7/yr and remains less than 1.0E-6 change in LERF. For this change in LERF to be acceptable, total LERF must be less than 1.0E-5. The total LERF value is calculated below:

$$\mathrm{LERF} = \mathrm{LERF_{internal}} + \mathrm{LERF_{fire}} + \mathrm{LERF_{seismic}} + \mathrm{LERF_{other}} + \mathrm{LERF_{class3Bincrease}}$$
$$= 2.69\mathrm{E}\text{-}7/\mathrm{yr} + 2.17\mathrm{E}\text{-}6/\mathrm{yr} + 6.24\mathrm{E}\text{-}7/\mathrm{yr} + 1.02\mathrm{E}\text{-}7/\mathrm{yr} + 2.55\mathrm{E}\text{-}7/\mathrm{yr} = 3.42\mathrm{E}\text{-}6/\mathrm{yr}$$

As specified in Regulatory Guide 1.174 [Reference 4], since the total LERF is less than 1.0E-5, it is acceptable for the ΔLERF to be between 1.0E-7 and 1.0E-6.

5.3.1.1 Calculating Class 3b Contribution without Subtracting LERF

The Finding against LE-E3 indicates the LERF definition may cause some sequences to be misclassified, and therefore, LERF to be miscalculated (see Table A-1 in Attachment A). A sensitivity is done where LERF is not subtracted from CDF before multiplying by the probability of a Class 3b leak. The results are shown in Table 5-18.

Table 5-18 – JAF Revised Methodology for ILRT LERF Calculation

Hazard	EPRI Accident Class 3b Frequency			LERF Increase (from 3 per 10 years to 1 per 15 years)
	3 per 10 year	1 per 10 year	1 per 15 years	
External Events	6.50E-08	2.17E-07	3.25E-07	2.60E-07
Internal Events	6.04E-09	2.01E-08	3.02E-08	2.42E-08
Combined	7.10E-08	2.37E-07	3.55E-07	2.84E-07

As shown in Table 5-18, the estimated change in LERF of 2.42E-8 for internal events is less than the Regulatory Guide 1.174 [Reference 4] threshold criteria for a very small change when comparing the 15-year results to the current 10-year requirement and the original 3-year requirement.

When both the internal and external event contributions are combined, the total change in LERF of 2.84E-7 meets the guidance for small change in risk, as it exceeds the 1.0E-7/yr and remains less than 1.0E-6 change in LERF. For this change in LERF to be acceptable, total LERF must be less than 1.0E-5. The total LERF value is calculated below:

$$\mathrm{LERF} = \mathrm{LERF_{internal}} + \mathrm{LERF_{fire}} + \mathrm{LERF_{seismic}} + \mathrm{LERF_{other}} + \mathrm{LERF_{class3Bincrease}}$$
$$= 2.69\mathrm{E}\text{-}7/\mathrm{yr} + 2.17\mathrm{E}\text{-}6/\mathrm{yr} + 6.24\mathrm{E}\text{-}7/\mathrm{yr} + 1.02\mathrm{E}\text{-}7/\mathrm{yr} + 2.84\mathrm{E}\text{-}7/\mathrm{yr} = 3.45\mathrm{E}\text{-}6/\mathrm{yr}$$

As specified in Regulatory Guide 1.174 [Reference 4], since the total LERF is less than 1.0E-5, it is acceptable for the ΔLERF to be between 1.0E-7 and 1.0E-6.

5.3.2 Potential Impact from Steel Liner Corrosion Likelihood

A quantitative assessment of the contribution of steel liner corrosion likelihood impact was performed for the risk impact assessment for extended ILRT intervals. As a sensitivity run, the internal event CDF was used to calculate the Class 3b frequency. The impact on the Class 3b frequency due to increases in the ILRT surveillance interval was calculated for steel liner corrosion likelihood using the relationships described in Section 5.2.6. The EPRI Category 3b frequencies for the 3 per 10-year, 10-year, and 15-year ILRT intervals were quantified using the internal events CDF. The change in the LERF, change in CCFP, and change in Annual Dose Rate due to extending the ILRT interval from 3 in 10 years to 1 in 10 years, or to 1 in 15 years are provided in Table 5-19 – Table 5-21. The steel liner corrosion likelihood was increased by a factor of 1000, 10000, and 100000. Except for extreme factors of 10000 and 100000, the corrosion likelihood is relatively insensitive to the results.

Table 5-19 – Steel Liner Corrosion Sensitivity Case: 3B Contribution

	3b Frequency (3-per-10 year ILRT)	3b Frequency (1-per-10 year ILRT)	3b Frequency (1-per-15 year ILRT)	LERF Increase (3-per-10 to 1-per-10)	LERF Increase (3-per-10 to 1-per-15)	LERF Increase (1-per-10 to 1-per-15)
Internal Event 3B Contribution	5.43E-09	1.81E-08	2.71E-08	1.27E-08	2.17E-08	9.05E-09
Corrosion Likelihood X 1000	5.48E-09	1.92E-08	3.11E-08	1.37E-08	2.56E-08	1.18E-08
Corrosion Likelihood X 10000	6.02E-09	2.94E-08	6.64E-08	2.34E-08	6.04E-08	3.70E-08
Corrosion Likelihood X 100000	1.13E-08	1.31E-07	4.20E-07	1.20E-07	4.09E-07	2.89E-07

Table 5-20 – Steel Liner Corrosion Sensitivity: CCFP

	CCFP (3-per-10 year ILRT)	CCFP (1-per-10 year ILRT)	CCFP (1-per-15 year ILRT)	CCFP Increase (3-per-10 to 1-per-10)	CCFP Increase (3-per-10 to 1-per-15)	CCFP Increase (1-per-10 to 1-per-15)
Baseline CCFP	7.80E-01	7.85E-01	7.88E-01	4.80E-03	8.24E-03	3.43E-03
Corrosion Likelihood X 1000	7.80E-01	7.85E-01	7.88E-01	4.86E-03	8.33E-03	3.47E-03
Corrosion Likelihood X 10000	7.80E-01	7.85E-01	7.89E-01	5.33E-03	9.13E-03	3.81E-03
Corrosion Likelihood X 100000	7.82E-01	7.92E-01	7.99E-01	1.00E-02	1.72E-02	7.17E-03

Table 5-21 –Steel Liner Corrosion Sensitivity: Dose Rate

	Dose Rate (3-per-10 year ILRT)	Dose Rate (1-per-10 year ILRT)	Dose Rate (1-per-15 year ILRT)	Dose Rate Increase (3-per-10 to 1-per-10)	Dose Rate Increase (3-per-10 to 1-per-15)	Dose Rate Increase (1-per-10 to 1-per-15)
Dose Rate	1.61E-03	5.37E-03	8.06E-03	3.76E-03	6.45E-03	2.69E-03
Corrosion Likelihood X 1000	1.63E-03	5.71E-03	9.22E-03	4.08E-03	7.59E-03	3.52E-03
Corrosion Likelihood X 10000	1.79E-03	8.73E-03	1.97E-02	6.95E-03	1.79E-02	1.10E-02
Corrosion Likelihood X 100000	3.37E-03	3.90E-02	1.25E-01	3.56E-02	1.21E-01	8.57E-02

5.3.3 Expert Elicitation Sensitivity

Another sensitivity case on the impacts of assumptions regarding pre-existing containment defect or flaw probabilities of occurrence and magnitude, or size of the flaw, is performed as described in Reference 24. In this sensitivity case, an expert elicitation was conducted to develop probabilities for pre-existing containment defects that would be detected by the ILRT only based on the historical testing data.

Using the expert knowledge, this information was extrapolated into a probability-versus-magnitude relationship for pre-existing containment defects. The failure mechanism analysis also used the historical ILRT data augmented with expert judgment to develop the results. Details of the expert elicitation process and results are contained in Reference 24. The expert elicitation process has the advantage of considering the available data for small leakage events, which have occurred in the data, and extrapolate those events and probabilities of occurrence to the potential for large magnitude leakage events.

The expert elicitation results are used to develop sensitivity cases for the risk impact assessment. Employing the results requires the application of the ILRT interval methodology using the expert elicitation to change the probability of pre-existing leakage in the containment.

The baseline assessment uses the Jeffreys non-informative prior and the expert elicitation sensitivity study uses the results of the expert elicitation. In addition, given the relationship between leakage magnitude and probability, larger leakage that is more representative of large early release frequency, can be reflected. For the purposes of this sensitivity, the same leakage magnitudes that are used in the basic methodology (i.e., 10 L_a for small and 100 L_a for large) are used here. Table 5-22 presents the magnitudes and probabilities associated with the Jeffreys non-informative prior and the expert elicitation used in the base methodology and this sensitivity case.

Table 5-22 – JAF Summary of ILRT Extension Using Expert Elicitation Values (from Reference 24)

Leakage Size (L_a)	Jeffreys Non-Informative Prior	Expert Elicitation Mean Probability of Occurrence	Percent Reduction
10	2.70E-02	3.88E-03	86%
100	2.70E-03	9.86E-04	64%

Taking the baseline analysis and using the values provided in Tables 5-10 and 5-10 for the expert elicitation sensitivity yields the results in Table 5-23.

Table 5-23 – JAF Summary of ILRT Extension Using Expert Elicitation Values

Accident Class	ILRT Interval							
	3 per 10 Years				1 per 10 Years		1 per 15 Years	
	Base Frequency	Adjusted Base Frequency	Dose (person-rem)	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)	Frequency	Dose Rate (person-rem/yr)
1	5.86E-07	5.86E-07	2.97E+03	1.74E-03	5.47E-07	1.63E-03	5.28E-07	1.57E-03
2	3.31E-09	3.31E-09	6.93E+05	2.29E-03	3.31E-09	2.29E-03	3.31E-09	2.29E-03
3a	N/A	9.18E-09	2.97E+04	2.73E-04	3.06E-08	9.09E-04	4.59E-08	1.36E-03
3b	N/A	2.33E-09	2.97E+05	6.93E-04	7.77E-09	2.31E-03	1.17E-08	3.46E-03
6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7a	5.39E-07	5.39E-07	1.28E+06	6.87E-01	5.39E-07	6.87E-01	5.39E-07	6.87E-01
7b	1.49E-06	1.49E-06	6.81E+05	1.01E+00	1.49E-06	1.01E+00	1.49E-06	1.01E+00
8	2.05E-08	2.05E-08	4.55E+05	9.33E-03	2.05E-08	9.33E-03	2.05E-08	9.33E-03
Totals	2.63E-06	2.63E-06	N/A	1.71E+00	2.63E-06	1.72E+00	2.63E-06	1.72E+00
ΔLERF (3 per 10 yrs base)	N/A				5.44E-09		9.33E-09	
ΔLERF (1 per 10 yrs base)	N/A				N/A		3.89E-09	
CCFP	77.42%				78.07%		78.21%	

The results illustrate how the expert elicitation reduces the overall change in LERF and the overall results are more favorable with regard to the change in risk.

5.3.4 Large Leak Probability Sensitivity Study

The large leak probability is a vital portion of determining the Class 3b frequency. A sensitivity is done by using the WCAP method as an alternative to the EPRI method for calculating the large leak probability. Table 5-24 presents the large leak probabilities for the baseline test, 10 year test interval, and 15 year test interval. Table 5-25 was developed using the same process as to calculate Class 3b.

Table 5-24 – JAF Large Leak Probabilities Using the WCAP Method

Test Interval	WCAP Large Leak Probability	EPRI Accident Class 3b Frequency
3 per 10 years	2.47E-4	5.84E-10
10 years	7.41E-4	1.75E-09
15 years	1.11E-3	2.63E-09

Using the same EPRI approach, but with an updated Class 3b frequency calculated from the WCAP large leak probability data, Table 5-25 contains the final results.

Table 5-25 – Impact on LERF due to Extended Type A Testing Intervals with WCAP CDF

ILRT Inspection Interval	3 Years (baseline)	10 Years	15 Years
Class 3b (Type A LERF)	5.84E-10	1.75E-09	2.63E-09
ΔLERF (3 year baseline)		1.17E-09	2.04E-09
ΔLERF (10 year baseline)			8.73E-10

These results demonstrate that the EPRI methodology is conservative when used to calculate a large leak probability as compared to the WCAP method.

5.3.5 Control Rod Drive Failure Sensitivity

Per a Finding against Supporting Requirement AS-B7, a bounding sensitivity is performed to determine the effect of the CRD system failing. The use of CRD for makeup does not account for time dependency. The success criteria for CRD indicate that it is not a valid source of makeup immediately after a transient. As a bounding sensitivity, CRD is completely failed in the model, and the results are applied to this ILRT extension application. Failing CRD results in a 6.4% increase in CDF. Tables 5-26 and 5-27 present the results of this quantification.

Table 5-26 – Release Category Frequencies

Release Category	Description of Outcome	EPRI Category	Frequency (/yr)
NCF	No Containment Failure	1	5.86E-07
CIS	Containment Isolation Failure	2	3.31E-09
LERF (no bypass)	Large Early Release Frequency (excluding containment bypass)	7a	2.49E-07
MERF	Medium Early Release Frequency	7a	3.35E-08
SERF	Small Early Release Frequency	7a	3.42E-08
SSERF	Small-Small Early Release Frequency	7a	0.00E+00
LIRF	Large Intermediate Release Frequency	7a	0.00E+00
MIRF	Medium Intermediate Release Frequency	7a	0.00E+00
SIRF	Small Intermediate Release Frequency	7a	1.40E-07
SSIRF	Small-Small Intermediate Release Frequency	7a	8.16E-08
LLRF	Large Late Release Frequency	7b	1.33E-06
MLRF	Medium Late Release Frequency	7b	7.17E-08
SLRF	Small Late Release Frequency	7b	2.57E-07
SSLRF	Small-Small Late Release Frequency	7b	0.00E+00
ISLOCA	Interfacing Systems LOCA	8	9.64E-09
LOCAOC	LOCA Outside Containment (that leads to LERF)	8	1.09E-08
	Contribution to EPRI Classification 2		3.31E-09
	Contribution to EPRI Classification 7a		5.39E-07
	Contribution to EPRI Classification 7b		1.66E-06
	Contribution to EPRI Classification 8		2.05E-08

Table 5-27 – CRD Sensitivity Baseline Risk Profile

Class	Description	Frequency (/yr)
1	No containment failure	5.57E-07[2]
2	Large containment isolation failures	3.31E-09
3a	Small isolation failures (liner breach)	2.34E-08
3b	Large isolation failures (liner breach)	5.81E-09
4	Small isolation failures - failure to seal (type B)	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]
7a	Severe accident phenomena induced failure (early)	5.39E-07
7b	Severe accident phenomena induced failure (late)	1.66E-06
8	Containment bypass	2.05E-08
	Total	2.80E-06

1. ε represents a probabilistically insignificant value or a Class that is unaffected by the Type A ILRT.
2. The Class 3a and 3b frequencies are subtracted from Class 1 to preserve total CDF.

The same methodology as described in Section 5.2 is used to perform this sensitivity. As can be seen, even with the CRD system failed, the estimated change in LERF is much less than the threshold criteria for a small change when comparing the 15-year results to the current 10-year requirement and the original 3-year requirement. Table 5-28 summarizes the impact on LERF of this bounding sensitivity. Table 5-29 summarizes the impact on population dose of this bounding sensitivity.

Table 5-28 – CRD Sensitivity: Impact on LERF due to Extended Type A Testing Intervals

ILRT Inspection Interval	3 Years (baseline)	10 Years	15 Years
Class 3b (Type A LERF)	5.81E-09	1.94E-08	2.91E-08
ΔLERF (3 year baseline)		1.36E-08	2.33E-08
ΔLERF (10 year baseline)			9.69E-09

Table 5-29 – CRD Sensitivity: Impact on Dose Rate due to Extended Type A Testing Intervals

ILRT Inspection Interval	10 Years	15 Years
ΔDose Rate (3 year baseline)	5.44E-03	9.33E-03
ΔDose Rate (10 year baseline)		3.89E-03
%ΔDose Rate (3 year baseline)	0.298%	0.510%
%ΔDose Rate (10 year baseline)		0.212%

6.0 RESULTS

The results from this ILRT extension risk assessment for JAF are summarized in Table 6-1.

Table 6-1 – ILRT Extension Summary

Class	Dose (person-rem)	Base Case 3 in 10 Years		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		Frequency	Person-Rem/Year	Frequency	Person-Rem/Year	Frequency	Person-Rem/Year
1	9.15E+02	5.58E-07	1.66E-03	4.95E-07	1.47E-03	4.50E-07	1.34E-03
2	6.93E+05	3.31E-09	2.29E-03	3.31E-09	2.29E-03	3.31E-09	2.29E-03
3a	9.15E+03	2.18E-08	6.47E-04	7.27E-08	2.16E-03	1.09E-07	3.24E-03
3b	9.15E+04	5.43E-09	1.61E-03	1.81E-08	5.37E-03	2.71E-08	8.06E-03
6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7a	1.28E+06	5.39E-07	6.87E-01	5.39E-07	6.87E-01	5.39E-07	6.87E-01
7b	6.81E+05	1.49E-06	1.01E+00	1.49E-06	1.01E+00	1.49E-06	1.01E+00
8	4.55E+05	2.05E-08	9.33E-03	2.05E-08	9.33E-03	2.05E-08	9.33E-03
Total		**2.63E-06**	**1.71E+00**	**2.63E-06**	**1.72E+00**	**2.63E-06**	**1.72E+00**
ILRT Dose Rate from 3a and 3b							
ΔTotal Dose Rate	From 3 Years	N/A		5.08E-03		8.71E-03	
	From 10 Years	N/A		N/A		3.63E-03	
%ΔDose Rate	From 3 Years	N/A		0.296%		0.508%	
	From 10 Years	N/A		N/A		0.211%	
3b Frequency (LERF)							
ΔLERF	From 3 Years	N/A		1.27E-08		2.17E-08	
	From 10 Years	N/A		N/A		9.04E-09	
CCFP %							
ΔCCFP%	From 3 Years	N/A		0.480%		0.824%	
	From 10 Years	N/A		N/A		0.343%	

7.0 CONCLUSIONS AND RECOMMENDATIONS

Based on the results from Section 5.2 and the sensitivity calculations presented in Section 5.3, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to 15 years:

- Regulatory Guide 1.174 [Reference 4] provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Regulatory Guide 1.174 defines very small changes in risk as resulting in increases of CDF less than 1.0E-06/year and increases in LERF less than 1.0E-07/year. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in internal events LERF resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years is estimated as 2.17E-8/year using the EPRI guidance; this value increases slightly to 2.20E-8/year if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. As such, the estimated change in LERF is determined to be "very small" using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- The effect resulting from changing the Type A test frequency to 1-per-15 years, measured as an increase to the total integrated plant risk for those accident sequences influenced by Type A testing, is 0.0087 person-rem/year. EPRI Report No. 1009325, Revision 2-A [Reference 24] states that a very small population dose is defined as an increase of ≤ 1.0 person-rem per year, or ≤ 1% of the total population dose, whichever is less restrictive for the risk impact assessment of the extended ILRT intervals. The results of this calculation meet these criteria. Moreover, the risk impact for the ILRT extension when compared to other severe accident risks is negligible.
- The increase in the conditional containment failure probability from the 3 in 10 year interval to 1 in 15 year interval is 0.824%. EPRI Report No. 1009325, Revision 2-A [Reference 24] states that increases in CCFP of ≤ 1.5% is very small. Therefore, this increase is judged to be very small.
- Several sensitivities are performed in Section 5.3. As shown in Section 5.3.1, when both the internal and external event contributions are combined, the total change in LERF of 2.55E-7 meets the guidance for small change in risk, as it exceeds 1.0E-7/yr and remains less than 1.0E-6 change in LERF and the total LERF is 3.42E-6. Other sensitivities show the baseline ILRT extension analysis (as performed in Section 5.2) is conservative.

Therefore, increasing the ILRT interval to 15 years is considered to be insignificant since it represents a very small change to the JAF risk profile.

<u>Previous Assessments</u>

The NRC in NUREG-1493 [Reference 6] has previously concluded that:

- Reducing the frequency of Type A tests (ILRTs) from 3 per 10 years to 1 per 20 years was found to lead to an imperceptible increase in risk. The estimated increase in risk is very small because ILRTs identify only a few potential containment leakage paths that cannot be identified by Type B or Type C testing, and the leaks that have been found by Type A tests have been only marginally above existing requirements.
- Given the insensitivity of risk to containment leakage rate and the small fraction of leakage paths detected solely by Type A testing, increasing the interval between

integrated leakage-rate tests is possible with minimal impact on public risk. The impact of relaxing the ILRT frequency beyond 1 in 20 years has not been evaluated. Beyond testing the performance of containment penetrations, ILRTs also test integrity of the containment structure.

The findings for JAF confirm these general findings on a plant-specific basis considering the severe accidents evaluated for JAF, the JAF containment failure modes, and the local population surrounding JAF.

A. ATTACHMENT 1 – PRA TECHNICAL ADEQUACY

A.1. Internal Events PRA Quality Statement for Permanent 15-Year ILRT Extension

The JAF PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause failure events. The PRA model quantification process used for the JAF PRA is based on the event tree and fault tree methodology, which is a well-known methodology in the industry.

Entergy employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating Entergy nuclear power plants. This approach includes both a proceduralized PRA maintenance and update process, and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the JAF PRA model.

A.1.1 PRA Maintenance and Update

The Entergy risk management process ensures that the applicable PRA model is an accurate reflection of the as-built and as-operated plant. This process is defined in the procedure EN-DC-151, "PSA Maintenance and Update." This procedure delineates the responsibilities and guidelines for updating the full power internal events PRA models at all operating Entergy nuclear power plants. In addition, the procedure also defines the process for implementing regularly scheduled and interim PRA model updates, and for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, industry operating experience, etc.). To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plant, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model. Potential PRA model changes resulting from these reviews are entered into the Model Change Request (MCR) database, and a determination is made regarding the significance of the change with respect to the current PRA model.
- New engineering calculations and revisions to existing calculations are reviewed for their impact on the PRA model.
- Plant-specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated approximately every four years, and
- Industry standards, experience, and technologies are periodically reviewed to ensure that any changes are appropriately incorporated into the models.

In addition, following each periodic PRA model update, Entergy performs a self-assessment to assure that the PRA quality and expectations for all current applications are met. The Entergy PRA maintenance and update procedure requires updating of all risk informed applications that may have been impacted by the update including but not limited to:

- System/component risk significance rankings
- PRA training materials
- AOV / MOV Risk Rankings
- Online Risk Model (EOOS)
- Mitigating System Performance Index input (MSPI)

A.1.2 BWROG Regulatory Guide 1.200 Peer Review of the JAF PRA Model

The JAF PRA internal events model went through BWROG Regulatory Guide 1.200 peer review in September 2009. The NEI 05-04 process [Reference 33], the American Society of Mechanical Engineers/American Nuclear Society (ASME/ANS) PRA Standard [Reference 27], and Regulatory Guide 1.200, Rev. 2 [Reference 38]) were used for the peer review.

The 2009 JAF PRA Peer Review was a full-scope review of all the Technical Elements of the internal events, at-power PRA:

- Initiating Events Analysis (IE)
- Accident Sequence Analysis (AS)
- Success Criteria (SC)
- Systems Analysis (SY)
- Human Reliability Analysis (HR)
- Data Analysis (DA)
- Internal Flooding (IF)
- Quantification (QU)
- LERF Analysis (LE)
- Maintenance and Update Process (MU)

The JAF PRA Peer Review process uses capability categories to assess the relative technical merits and capabilities of each technical supporting requirement reviewed. Three capability category levels are used to indicate the relative quality level of each supporting requirement. Capability category assignments are made based on the judgment of the Peer Review Team after reviewing: (1) the PRA model, (2) the documentation; and, (3) the prior PRA Peer Review results (for historical background).

During the JAF PRA model Peer Review, the technical elements identified above were assessed with respect to Capability Category II criteria to better focus the Supporting Requirement assessments. The ASME/ANS PRA Standard has 326 individual Supporting Requirements; 310 Supporting Requirements are applicable to the JAF PRA model. Sixteen (16) of the ASME/ANS PRA Standard Supporting Requirements are not applicable to JAF (e.g., PWR related, multi-site related). Of the 310 ASME/ANS PRA Standard Supporting Requirements applicable to the JAF PRA model, approximately 94% satisfied Capability Category II criteria or greater. Of the 53 Findings and Observations (F&Os) generated by the Peer Review Team, 24 were considered Findings, 27 were Suggestions, and 2 were Best Practices.

A.1.3 Consistency with Applicable PRA Standards

As a result of the BWROG Regulatory Guide 1.200 peer review, 51 F&Os have been identified for potential improvement to the JAF PRA model. These F&Os are tracked in the Entergy Model Change Request (MCR) database. Of the identified 51 F&Os, 21 were considered not meeting at least the Capability Category II criteria. Table A-1 summarizes the open F&Os along with an initial assessment of the impact for this application. For each F&O in Table A-1, applicability for this ILRT extension application is evaluated. If an impact is not expected to be negligible, then this assessment may include the performance of additional sensitivity studies or PRA model changes to confirm the impact on the risk analysis and justify why the change does not impact the PRA results used to support the application. Table A-2 summarizes the closed F&Os and the actions taken to close the F&Os.

A.2. External Events PRA Quality Statement for Permanent 15-Year ILRT Extension

External hazards were evaluated in 1996 in the JAF Individual Plant Examination of External Events (IPEEE) submittal in response to the NRC IPEEE Program (Generic Letter 88-20, Supplement 4) [Reference 39]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

The results of the JAF IPEEE study are documented in the JAF IPEEE Report [Reference 35]. The primary areas of external event evaluation at JAF were internal fire, seismic, high winds, floods, and other external hazards.

A.2.1 Fire Analysis

The JAF IPEEE fire analysis was performed using EPRI's Fire PRA Implementation Guide [Reference 40]. The EPRI Fire-Induced Vulnerability Evaluation method was used for the initial screening, for treatment of transient combustibles, and as the source of fire frequency data [Reference 41].

The fire analysis was revised after the original IPEEE submittal in response to NRC requests for additional information (RAIs) regarding fire-modeling progression, developed during their review of the IPEEE. The updated results are reflected in NUREG-1742, "Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program" [Reference 42] for JAF. In addition, as noted in that NUREG, a number of plant and procedural changes (including strict limitations on storage and use of combustible and flammable material in plant areas) were made as a result of the IPEEE fire analysis. The impact of these enhancements is not reflected in the IPEEE fire results.

Other changes to the plant configuration, procedures and equipment performance have also taken place since completion of the IPEEE. These changes would tend to reduce the overall CDF as well as the fire risk contribution found in the IPEEE. The significant reduction in the internal events CDF since the original JAF IPEEE submittal bears this out. These changes include the following:

- Service, instrument, and breathing air compressors were replaced.
- Operators are directed to maximize CRD flow in certain accident sequences.
- SRV Electric Lift mod to install an SRV alternate actuation system.
- A new procedure (EP-10) directs operators to align the fire protection system to the tube side of the RHR heat exchanger in loss of containment heat removal accident sequences.
- Revised station blackout procedures to explicitly address bus recovery.
- Provision of a back-up battery charger that can be aligned to either station battery.
- Proceduralized RCIC operation without DC power.
- Proceduralized starting EDG without DC power, as well as field flashing without station batteries.

Thus, although the JAF IPEEE fire risk model has not been updated since its original issuance, use of the IPEEE model would tend to give conservative results.

A.2.2 Seismic Analysis

In the IPEEE, FitzPatrick performed a SMA, which is a deterministic and conservative evaluation that does not calculate risk on a probabilistic basis.

A.2.3 High Winds, Floods, and Other External Hazards (HFO)

In addition to internal fires and seismic events, the JAF IPEEE analysis of HFO external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Since JAF was designed (with construction started) prior to the issuance of the 1975 Standard Review Plan (SRP) criteria, JAF performed a plant hazard and design information review for conformance with the SRP criteria. For HFO events that were not screened out by compliance with the 1975 SRP criteria, additional analyses were performed to determine whether or not the hazard frequency was acceptably low. Based on those analyses, these hazards were determined in the JAF IPEEE to be negligible contributors to overall plant risk.

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
Finding	The use of CRD for makeup does not account for time dependency. Gate U3 is used after containment heat removal fails and venting is a success. The success criteria for CRD indicate that it is not a valid source of makeup immediately after a transient. It is implicit that HPCI or RCIC work until containment is vented.	AS-B7	MODEL time-phased dependencies (i.e., those that change as the accident progresses, due to such factors as depletion of resources, recovery of resources, and changes in loads) in the accident sequences.	Open. Although success of early injection (from HPCI, RCIC, LPCI, core spray) is not explicitly modeled in the event trees, CRD is only credited on the success branch, because early injection sequences (if initially successful) fail long-term due to the accident phenomena cause by the loss of containment heat removal. In addition, the random failure of early injection based on past event tree development is truncated out during accident sequence quantification.	Not significant. Changes in the ILRT frequency is not relevant to the modeling of the long-term use of the CRD system as a source of RPV injection during a loss of containment decay heat event. A bounding sensitivity study performed in Section 5.3.5 shows that removing all credit for CRD resulted in a 6.4% increase in CDF and no increase in LERF. As shown in Section 5.3.5, this results in an increase in ΔLERF of 7.2%, to 2.33E-08, which is well within Region III of the R.G. 1.174 criteria. Therefore, this F&O has no impact on the ILRT extension application.
Finding	Appendix H4 states that 'When applying the dependency model, the dependency was generally applied to the HEP with the higher HEP (versus assigning the dependency to the action which occurs later in time). This does not conform to the established calculation method. In general, it is more appropriate to choose the event that would occur first	HR-G7	For multiple human actions in the same accident sequence or cut set, identified in accordance with supporting requirement QU-C1, ASSESS the degree of dependence, and calculate a joint human error probability that reflects the dependence. ACCOUNT for the influence of success or failure in preceding human actions and system performance on the human event under consideration including	Open. The HRA guidance on assessing dependency between post-initiator HFEs has been modified to incorporate this peer review comment. However, the new HRA guidance has not yet been incorporated into the JAF PRA model.	Not significant. This change does not have a significant impact on the results. There is an observation that the lower probability HFEs generally occur earlier in the sequences; this is an observation of the important HEPs to the JAF model (not an assertion about all PRAs). The assigned dependencies are often conservative because they are based on the overall HEP value

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
	in the accident sequence. The reason for this is that if the operators failed on the first action, then they are more likely to fail on subsequent actions (unless there is an intervening success). If the events occur relatively close in time, then it may be acceptable to choose the one with the lowest probability. The reason for this is that the lower probability is usually the easier action to perform or the one with more time available.		(a) time required to complete all actions in relation to the time available to perform the actions (b) factors that could lead to dependence (e.g., common instrumentation, common procedures, increased stress, etc.) (c) availability of resources (e.g., personnel)		(whereas dependency between the execution portions of the HEPs can frequently be justified as being low or zero). Re-analysis of the combined HEPs to address this F&O resulted in a CDF increase of 1.73% and a LERF increase of 0.02%. These increases are bounded by the sensitivity study described in the evaluation of the F&O regarding AS-B7 (the increase in total LERF does not impact the criteria in Region III and not subtracting it from the 3b frequency calculation is conservative since all additional CDF is assumed to be a class 3b LERF); therefore, there is no impact on the ILRT extension application.
Finding	The JAF PRA determined a point estimate for core damage and documented an analysis for parametric uncertainty. However, the state of knowledge correlation was not fully accounted for due to the manner in which the JAF basic event data base is constructed.	QU-A3	ESTIMATE the mean CDF accounting for the state-of-knowledge correlation between event probabilities when significant.	Open. As future updates are performed, the state of knowledge correlation (SOKC) will be re-examined as part of the quantification process.	Not significant. A sensitivity performed at the time of the RG 1.200 peer review demonstrated that the state of knowledge correlation is not a significant issue for the current JAF PRA model. This is evidenced by the fact that the mean and point estimate CDF and LERF values are very close in value.

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
Finding	Ranking of components by RAW and RRW is presented in tables I.3-1 and I.3-2. However, no discussion was found with respect to the reasonableness of the ranking.	QU-D7	REVIEW the importance of components and basic events to determine that they make logical sense.	Open. Reasonableness of the SSC rankings was verified through a review of the results, which was performed prior to issuing the PSA report.	None. This is a documentation issue only.
Finding	The level 2 model uses point estimates for success branches while the failure logic is modeled for the failure branch	LE-C4	INCLUDE model logic necessary to provide a realistic estimation of the significant accident progression sequences resulting in a large early release. INCLUDE mitigating actions by operating staff, effect of fission product scrubbing on radionuclide release, and expected beneficial failures in significant accident progression sequences. PROVIDE technical justification (by plant-specific or application generic calculations demonstrating the feasibility of the actions, scrubbing mechanisms, or beneficial failures) supporting the inclusion of any of these features.	Open. For Level 2 top events that include severe accident phenomena, those phenomena dominate and use of point estimate values is typical and appropriate. Where phenomena are not involved, system related success terms do not influence the outcome of the sequence quantification.	Not significant. Since use of point estimates is reasonable for top events that include phenomena, and system related success probabilities are approximately equal to 1.0, no impact on the application is expected.
Finding	The definition of 'Early' is inconsistent within the document and may classify some LERF sequences as non-LERF.	LE-E3	INCLUDE as LERF contributors potential large early release (LER) sequences identified from the results of the accident progression analysis of LE-C except those LER sequences justified as non-LERF contributors in LE-C1.	Open. Resolution of this F&O entails defining an ‘Early’ release based on the time to declare a ‘General Emergency’ and subsequent linking of each accident progression sequence to a declaration time for	Minimal. It is possible this issue causes LERF to be slightly miscalculated. A bounding sensitivity is performed in Section 5.3.1.1; it shows any change from resolving this F&O is insignificant to this application. Also, as shown in

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
				comparison to the 'Early' criterion.	Sections 5.2.5, 5.3.1, and 5.3.1.1, there is significant margin between the calculated results and the Regulatory Guide 1.174 [Reference 4] threshold criteria. Therefore, a small change in LERF will not affect the conclusions of this calculation.
Finding	Spray-induced and submergence induced failures appear to have been addressed in the analysis. No documentation of a systematic assessment of the effects of jet impingement, pipe whip, humidity, temperature, etc., on SSCs could be identified. No evaluation of the specific equipment evaluated in the PRA compared to equipment considered in the design analyses, e.g., EQ lists, was documented. Since the PRA can credit non-safety-related equipment, relying on design basis evaluations to dismiss these dynamic effects may credit equipment that cannot withstand the effects considered in the design analysis. In	IFSN-A6	For the SSCs identified in IFSN-A5, IDENTIFY the susceptibility of each SSC in a flood area to flood-induced failure mechanisms INCLUDE failure by submergence and spray in the identification process. EITHER (a) ASSESS qualitatively the impact of flood-induced mechanisms that are not formally addressed (e.g., using the mechanisms listed under Capability Category III of this requirement), by using conservative assumptions; OR (b) NOTE that these mechanisms are not included in the scope of the evaluation	Open. The additional impacts noted in the F&O are only required for Capability Category III. The only requirement to meet Capability Category II is to document that those mechanisms are not included in the scope. This will be documented in a future update.	None. This is a documentation issue only.

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
	addition, failure in a system containing high temperature fluid can actuate fire systems and impact additional equipment. Also, the PRA models may evaluate breaks beyond those of the design basis.				
Finding	Although the corresponding initiating event group is identified for several of the internal flooding scenarios, there is no such information provided in the internal flooding documentation for the vast majority of the scenarios.	IFEV-A1	For each flood scenario, IDENTIFY the corresponding plant initiating event group identified per 2-2.1 and the scenario-induced failures of SSCs required to respond to the plant initiating event. INCLUDE the potential for a flooding-induced transient or LOCA. If an appropriate plant-initiating event group does not exist, CREATE a new plant-initiating event group in accordance with the applicable requirements of 2-2.1.	Open. Although not specifically provided in the internal flooding analysis documentation, the link to the initiating event utilized and the impacted equipment is provided in the flag file for each flooding initiator.	None. This is a documentation enhancement issue.
Finding	Quantification of initiating event frequency is not documented in the Internal Flooding Analysis. A series of spreadsheets that were used to quantify internal flooding initiating event frequency values were provided. The documentation does not allow a reviewer to	IFEV-A5	DETERMINE the flood initiating event frequency for each flood scenario group by using the applicable requirements in 2-2.1.	Open. As noted, the required information is provided in a series of spreadsheets. These spreadsheets will be integrated in a single easily reviewed format in a future update.	None. This is a documentation enhancement issue.

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
	correlate the piping and areas considered for each initiating event without recourse to the author and spreadsheets that are maintained outside of the approved documentation.				
Finding	Review and consideration of plant-specific information is required by the SR to meet Capability Category II.	IFEV-A6	GATHER plant-specific information on plant design, operating practices, and conditions that may impact flood likelihood (i.e., material condition of fluid systems, experience with water hammer, and maintenance-induced floods). In determining the flood-initiating event frequencies for flood scenario groups, USE a combination of the following: (a) generic and plant-specific operating experience (b) pipe, component, and tank rupture failure rates from generic data sources and plant-specific experience (c) engineering judgment for consideration of the plant-specific information collected	Open. A search of the JAF condition reporting system was performed for a period of 15 years for the Internal Flooding Analysis. No significant internal flooding events were identified which would significantly alter the generic data.	Not significant. Since plant specific data was reviewed for applicability and determined not to change the input, this is considered a documentation enhancement issue.
Finding	Appendix C does not contain evidence of a review of initiating events for applicability during flood scenarios. The development of event trees and selection of initiating	IFQU-A1	For each flood scenario, REVIEW the accident sequences for the associated plant initiating event group to confirm applicability of the accident sequence model. If appropriate accident sequences do not exist, MODIFY sequences	Open. Although not specifically provided in the internal flooding analysis documentation, evidence of the initiating event utilized and the impacted equipment	None. This is a documentation enhancement issue.

Table A-1 Internal Events PRA Peer Review – Open Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
	events is only briefly discussed in Section C3.3.		as necessary to account for any unique flood-induced scenarios and/or phenomena in accordance with the applicable requirements described in 2-2.2.	is provided in the flag file for each flooding initiator.	

Table A-2 Internal Events PRA Peer Review – Closed Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
Finding	The time dependency of the DC to support HPCI (U1) and RCIC (U2) is inadequate. The battery and chargers are both in an AND gate. This is incorrect for mission times greater than four hours. The battery, with load shed, will last four hours and needs the charger after that; therefore, the sole dependency should be on the battery charger.	AS-B7	MODEL time-phased dependencies (i.e., those that change as the accident progresses, due to such factors as depletion of resources, recovery of resources, and changes in loads) in the accident sequences.	Closed. Modified dependency logic for HPCI and RCIC fault trees (gates GHCI-FLC108 and GRCI-FLC-1391, respectively) to reflect that continued operation requires availability of both the charger and battery.	None. This F&O has been addressed and incorporated into the model.
Finding	Appendices E1-E36 show many systems where support systems are explicitly modeled or assumed to be necessary in the absence of engineering analyses to determine whether they are needed. Example: battery ventilation system.	SY-B6	PERFORM engineering analyses to determine the need for support systems that are plant-specific and reflect the variability in the conditions present during the postulated accidents for which the system is required to function.	Closed. Plant engineering analyses, where available, were used in modeling support systems. In the specific case of the battery ventilation system, the calculation did not provide sufficient basis for concluding that ventilation was unnecessary. Therefore, the Battery Room Ventilation System was included as a support system to the battery chargers.	None. Support system modeling was included where needed or best estimate analyses were not available or sufficient.

Table A-2 Internal Events PRA Peer Review – Closed Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
Finding	The majority of support systems are based on conservative success criteria and timing, but the criteria are not justified based on the impact on risk significant contributors.	SY-B7	BASE support system modeling on realistic success criteria and timing, unless a conservative approach can be justified (i.e., if their use does not impact risk significant contributors).	Closed. A further review of the existing support system success criteria documentation determined that use of conservative success criteria and timing was limited and where used, it had little impact on results.	None. This was a documentation issue only and has been addressed.
Finding	RCIC/HPCI flow is delivered to the reactor vessel via feedwater line A/B. The HPCI fault tree includes the failure of the downstream feedwater check valve and manual valve but the RCIC fault tree does not.	SY-B13	Some systems use components and equipment that are required for operation of other systems. INCLUDE components that, using the criteria in SY-A15, may be screened from each system model individually, if their failure affects more than one system (e.g., a common suction pipe feeding two separate systems).	Closed. The RCIC system fault tree has been revised to include the “A” feedwater check valve and manual valve.	None. This F&O has been addressed and incorporated into the model.
Finding	The documentation contained no evidence of checking the reasonableness of the posterior distribution.	DA-D4	When the Bayesian approach is used to derive a distribution and mean value of a parameter, CHECK that the posterior distribution is reasonable given the relative weight of evidence provided by the prior and the plant-specific data. Examples of tests to ensure that the updating is accomplished correctly and that the generic parameter estimates are consistent with the plant-specific application include the following: (a) confirmation that the Bayesian updating does not produce a posterior distribution with a single bin histogram (b) examination of the cause of any unusual (e.g., multimodal) posterior distribution shapes	Closed. Detailed discussions that describe the process of confirming the reasonableness of the posterior distribution mean value have been added to Appendix D.	None. This was a documentation issue only and has been addressed.

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F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
			(c) examination of inconsistencies between the prior distribution and the plant-specific evidence to confirm that they are appropriate (d) confirmation that the Bayesian updating algorithm provides meaningful results over the range of values being considered (e) confirmation of the reasonableness of the posterior distribution mean value		
Finding	Significant contributors to CDF by initiating events, accident sequence, systems and operator errors were identified and discussed in the Summary Report, Sections 3.2 through 3.6. A listing of basic event importance is provided in Appendix I.3. It does not appear the SSCs and HFEs associated with initiating events modeled by fault tree were included.	QU-D6	IDENTIFY significant contributors to CDF, such as initiating events, accident sequences, equipment failures, common cause failures, and operator errors. INCLUDE SSCs and operator actions that contribute to initiating event frequencies and event mitigation.	Closed. Significant contributors to CDF, such as initiating events, accident sequences, equipment failures, common cause failures, and operator errors were identified. The importance of SSCs and HFEs that contribute to initiating event frequencies and event mitigation are identified in the results to the extent possible. In general, it was found that basic events associated with initiating events which are important contributors to CDF will also be important for accident mitigation and their importance will be reasonably accounted for using the current method for importance ranking.	None. The importance of systems, components and operator actions has been reasonably accounted for in the PRA model.
Finding	While descriptions and some discussion of the top ten accident sequences are provided, additional information with regard	QU-F3	DOCUMENT the significant contributors (such as initiating events, accident sequences, basic events) to CDF in the PRA results summary.	Closed. Each of the top 95% accident sequences was provided with a description which summarizes the failures	None. This was a documentation issue only and

Table A-2 Internal Events PRA Peer Review – Closed Facts and Observations

F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
	to the contributors to the sequence frequency should be included.		PROVIDE a detailed description of significant accident sequences or functional failure groups.	and/or successes for that sequence. In addition, detailed descriptions were provided for all sequences in Appendix F.	has been addressed.
Finding	Accident sequences that credited reactor building plate-out (reducing the release magnitude one classification) have not been justified.	LE-C1	DEVELOP accident sequences to a level of detail to account for the potential contributors identified in LE-B1 and analyzed in LE-B2. Compare the containment challenges analyzed in LE-B with the containment structural capability analyzed in LE-D and identify accident progressions that have the potential for a large early release. JUSTIFY any generic or plant-specific calculations or references used to categorize releases and non-LERF contributors based on release magnitude or timing. NUREG/CR-6595, App. A [2-16] provides a discussion and examples of LERF source terms.	Closed. The appendix addressing radionuclide release impacts was modified to document that for sequences where the Reactor Building (RB) node is effective, MAAP calculations indicate a substantial reduction in the release.	None. This was considered a documentation issue only and has been addressed.
Finding	LERF sequences are identified by their containment failure (or bypass) mode and confirmed by accident progression calculations documented in Section J1.5.5 and Tables J1.5-6 and J1.5-8. Some MAAP runs in Table J1.5-6 labeled as Large-Early are not included in LERF because the MAAP run may only be implemented as a conservative run for a late scenario.	LE-E3	INCLUDE as LERF contributor potential large early release (LER) sequences identified from the results of the accident progression analysis of LE-C except those LER sequences justified as non-LERF contributors in LE-C1.	Closed. Added the following sentence to the last paragraph of Section J1.5.5: "Note that not all the MAAP analyses represented in Table J1.5-6 and Table J1.5-8 were used. The MAAP analyses selected reflect the most appropriate cases in terms of predicting the accident progression for each of the large early release endstates."	None. This was a documentation issue only and has been addressed.

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F&O Significance	Finding/Observation Description	Applicable SRs	SR Description	Current Status / Comment	Importance to Application
Finding	Limitations discussed in Appendix J are focused on model conservatisms and other LERF issues, but these limitations are not addressed in terms of their impact on applications.	LE-G5	IDENTIFY limitations in the LERF analysis that would impact applications.	Closed. A discussion was added in Appendix J to document that no limitations of the LERF quantification process were identified that would impact applications.	None. This was a documentation issue only and has been addressed.