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October 7, 2019

L-PI-19-040
10 CFR 50.90

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Prairie Island Nuclear Generating Plant, Units 1 and 2
Docket Nos. 50-282 and 50-306
Renewed Facility Operating License Nos. DPR-42 and DPR-60

License Amendment Request: Revise Technical Specification 5.5.14 to Permanently Extend Containment Leakage Rate Test Frequency

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (hereafter "NSPM"), requests a change to the Technical Specifications (TS) for the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2. The proposed change revises TS 5.5.14, "Containment Leakage Rate Testing Program," to increase the containment integrated leakage rate test (ILRT) program Type A test interval from 10 to 15 years and extend the containment isolation valve Type C leakage rate test frequency from 60 to up to 75 months based on an acceptable performance history. The basis for the proposed change is in accordance with the guidance of Nuclear Energy Institute (NEI) Topical Report NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Revision 3-A, as endorsed by the U.S. Nuclear Regulatory Commission.

The proposed license amendment request is risk-informed and follows the guidance provided by Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2.

Enclosure 1 provides NSPM's evaluation of the proposed change. The enclosure also provides the no significant hazards consideration evaluation in accordance with 10 CFR 50.92, "Issuance of Amendment," and the environmental assessment. These provide the bases for the conclusion that the amendment request involves no significant hazards consideration and meets the eligibility criterion for categorical exclusion as set forth in 10 CFR 51.22, "Criteria for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review," specifically paragraph (c)(9).

Attachment 1 to Enclosure 1 provides the marked-up TS page. Attachment 2 to Enclosure 1 provides the revised (retyped) TS page. Enclosure 2 provides the plant specific risk impact assessment of the proposed changes and provides documentation related to the technical adequacy of the PINGP Units 1 and 2 probabilistic risk assessment.

Approval of the proposed amendment is requested by November 6, 2020. Once approved, the amendment shall be implemented within 90 days.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), NSPM is notifying the State of Minnesota of this request by transmitting a copy of this letter and enclosures to the designated State Official.

If there are any questions or if additional information is needed, please contact Mr. Richard Loeffler at (612) 330-8981 or Richard.Loeffler@xenuclear.com.

Summary of Commitments

This letter makes no new commitments and no revisions to existing commitments.

I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on October 7, 2019.

Scott Sharp
Site Vice President, Prairie Island Nuclear Generating Plant
Northern States Power Company – Minnesota

Enclosures (2)

cc: Administrator, Region III, US NRC
Project Manager, Prairie Island, US NRC
Resident Inspector, Prairie Island, US NRC
State of Minnesota

ENCLOSURE 1

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2

EVALUATION OF THE PROPOSED CHANGE

LICENSE AMENDMENT REQUEST

REVISE TECHNICAL SPECIFICATION 5.5.14 TO PERMANENTLY EXTEND CONTAINMENT LEAKAGE RATE TEST FREQUENCY

LICENSE AMENDMENT REQUEST

REVISE TECHNICAL SPECIFICATION 5.5.14 TO PERMANENTLY EXTEND CONTAINMENT LEAKAGE RATE TEST FREQUENCY

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ATTACHMENTS:

1. Technical Specification Pages (Mark-up)
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LICENSE AMENDMENT REQUEST

REVISE TECHNICAL SPECIFICATION 5.5.14 TO PERMANENTLY EXTEND CONTAINMENT LEAKAGE RATE TEST FREQUENCY

1.0 SUMMARY DESCRIPTION

Pursuant to 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (hereafter "NSPM"), requests an amendment to revise the Technical Specifications (TS) for the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2. Specifically, the proposed change revises TS 5.5.14, "Containment Leakage Rate Testing Program," to require a program that is in accordance with Nuclear Energy Institute (NEI) topical report (TR) NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J" (Reference 1). Implementing the guidance of Revision 3-A of NEI-94-01 provides for:

- A permanent extension of the containment integrated leakage rate test (ILRT) (Type A) test interval from 10 years to 15 years in accordance with Revision 3-A of NEI 94-01.
- An extension of the containment isolation valve (CIV) leakage rate (Type C) test frequency from the 60 months currently permitted by "Option B – Performance-Based Requirements" of 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors" (Reference 2), to up to 75 months for selected components, based on an acceptable performance history in accordance with Revision 3-A of NEI 94-01.
- A more conservative grace period of up to 9 months for Type C leakage tests in accordance with Revision 3-A of NEI 94-01.
- The adoption of American National Standards Institute (ANSI) / American Nuclear Society (ANS) 56.8-2002, "Containment System Leakage Testing Requirements" (Reference 3).

The NRC has determined that NEI 94-01, Revision 3-A, provides an acceptable approach for implementing the performance-based requirements of Option B of 10 CFR 50, Appendix J, as modified by the conditions and limitations within the NRC Safety Evaluation (SE).

2.0 DETAILED DESCRIPTION

2.1 Current Technical Specification Requirements

TS 5.5.14, "Containment Leakage Rate Testing Program," currently states, in part:

> A program shall be established to implement 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:
>
> 1. Unit 1 and Unit 2 (steam generator (SG) replacement commencing Fall 2013) are excepted from post-modification integrated leakage rate testing requirements associated with SG replacement.
>
> 2. Exception to NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," Section 9.2.3, to allow the following:
>
>   (i). The first Unit 1 Type A test performed after December 1, 1997 shall be performed by December 1, 2012.
>
>   (ii). The first Unit 2 Type A test performed after March 7, 1997 shall be performed by March 7, 2012.

The proposed change to TS 5.5.14 replaces the reference to Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program" (Reference 4), with a reference to the NEI topical report NEI 94-01, Revision 3-A, and the conditions and limitations specified in NEI 94-01, Revision 2-A (Reference 5), as the documents used by NSPM to implement the performance-based leakage testing program in accordance with Option B of 10 CFR 50, Appendix J at the PINGP.

One administrative change is proposed by this license amendment request (LAR). It is proposed to remove expired exception Item 2 from TS 5.5.14. As a result of License Amendment Nos. 174 and 164, Item 2 delayed the requirement to perform a Type A test for PINGP Unit 1 to until December 1, 2012, and for PINGP Unit 2 to until March 7, 2012. These Type A tests were completed on October 31, 2012, for PINGP Unit 1 and on March 1, 2012, for PINGP Unit 2. The tests have been performed and this exception is no longer applicable.

The proposed change revises TS 5.5.14 to state, in part:

> A program shall be established to implement 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 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.

1. Unit 1 and Unit 2 (steam generator (SG) replacement commencing Fall 2013) are excepted from post-modification integrated leakage rate testing requirements associated with SG replacement.

Attachment 1 to Enclosure 1 provides existing TS 5.5.14 page marked up to indicate the proposed changes. Attachment 2 to Enclosure 1 provides the revised (retyped) TS page. There are no TS Bases associated with Section 5 of the TS which includes Section 5.5, "Programs and Manuals," subsection.

A plant-specific risk assessment entitled, "Prairie Island Nuclear Generating Plant, Evaluation of Risk Significance of Permanent ILRT Extension," performed by Jensen Hughes is provided in Enclosure 2. This assessment followed the guidelines of RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3 (Reference 6) and RG 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2 (Reference 7). The technical adequacy of the PINGP Units 1 and 2 probabilistic risk assessments (PRA) are discussed in Appendix A of the enclosure.

The risk assessment for PINGP Units 1 and 2 concluded that the increase in risk from changing the ILRT performance interval from 10 to 15 years is considered insignificant since it represents a very small change in the PINGP risk profile that is within the NRC established guidelines.

2.2 Facility Description

NSPM owns and operates the PINGP, which is a two unit plant located on the west bank of the Mississippi River near Red Wing, Minnesota. Each unit at PINGP employs a two-loop pressurized water reactor designed and supplied by Westinghouse Electric Corporation. The PINGP application for a Construction Permit and Operating License was submitted to the Atomic Energy Commission (AEC) on April 5, 1967. The Final Safety Analysis Report was submitted for application of an Operating License on February 1, 1971. Unit 1 began commercial operation on December 16, 1973, and Unit 2 began commercial operation on December 21, 1974. The PINGP Units 1 and 2 Renewed Facility Operating Licenses expire August 9, 2033, and October 29, 2034, respectively.

The PINGP was designed and constructed to comply with NSPM's understanding of the intent of the AEC 70 General Design Criteria for Nuclear Power Plant Construction Permits, as published on July 11, 1967. PINGP is not licensed to NUREG-0800, "Standard Review Plan."

2.3 Containment Design

The Prairie Island site contains two nuclear units. Each reactor Containment Vessel is a low leakage cylindrical steel pressure vessel with a hemispherical dome and ellipsoidal bottom which houses the reactor pressure vessel, the steam generators, reactor coolant pumps, the reactor coolant loops, the accumulators of the Safety Injection System, the primary coolant pressurizer, the pressurizer relief tank, and other branch connections of the Reactor Coolant System. No portion of either containment structural system is shared.

Each Containment Vessel has an inside diameter of 105 feet with an inside height of 206 feet 7-7/8 inches, and an internal net free volume of 1,320,000 cubic-feet. The reactor containment vessel polar crane girder is attached to the inside of the each vessel. Each Containment Vessel is supported on a grout base that was placed after the vessel construction was complete and tested. Both the Containment Vessel and the Shield Building for each unit are supported on a common foundation slab. Freedom of movement between each Containment Vessel and the respective Shield Building is virtually unlimited. With the exception of the support grout placed underneath and near the knuckle sides of the vessel, there are no structural ties between the Containment Vessels and the Shield Buildings above the foundation slab.

The nominal thickness of the plate for each Containment Vessel does not exceed 1-1/2 inches at the welded joints so the vessel, and as an integral structure did not require field stress relieving. Reinforcing plates at penetration openings exceed 1-1/2 inches in thickness; however, these were fabricated as penetration weldment assemblies and were stress relieved before they were welded to adjacent vessel shell plates.

Each Containment Vessel is designed for a maximum internal pressure of 46 (pounds per square inch gauge (psig) and a temperature of 268°F. The design internal pressure as defined by American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code is 41.4 psig. The temperature value of 268°F is specifically for the design of the containment shell.

Each Containment Vessel, including penetrations is designed for low leakage. The initial measured leakage rate was approximately 0.02 percent by weight in 24 hours at a nominal internal pressure of 46 psig.

Each Containment Vessel is completely enclosed by the Shield Building. Each Shield Building is a medium leakage building in the shape of a right circular cylinder 120 feet outside diameter with concrete walls 2 feet 6 inches thick. The roof of the Shield Buildings consists of a shallow dome roof 2 feet thick. The entire structure is 205 feet 4-1/2 inches from the top of the foundation mat to the top of the dome. An annular space of 5 feet is provided between the wall of each Containment Vessel and the Shield Building. A 7-foot clearance is also provided between the roofs of each Containment Vessel and the Shield Building.

The piping penetrations listed in Updated Safety Analysis Report (USAR) Table 5.2-1, except the containment vacuum breakers, penetrate the Shield Building as well as the Containment Vessel. All process lines traverse the boundary between the inside of the Containment Vessel and the outside of the Shield Building by means of piping penetration assemblies made up of several elements. Two general types of piping penetration assemblies are provided; i.e., those that are not required to accommodate thermal movement (cold penetrations) and those which accommodate thermal movement (hot penetrations).

Both hot and cold piping penetration assemblies consist of a containment penetration nozzle, a process pipe, a Shield Building penetration sleeve and a Shield Building seal. In the case of a cold penetration, the Containment Vessel penetration nozzle is an integral part of the process pipe, or for instrument tubing and some small bore piping the tube or pipe passes through and is welded to a plate which is in turn welded to the nozzle. For hot penetrations, a multiple-flued head becomes an integral part of the process pipe, and is used to attach a guard pipe and an expansion joint bellows. The expansion joint bellows is welded to the containment vessel penetration nozzle.

The main steam piping penetration assembly uses the same elements as a hot piping penetration assembly. In addition, the main steam line is anchored to the interior concrete of the Containment Vessel. A limit stop designed to control lateral movement but permits axial movement is provided around each main steam line inside containment. This limit stop serves to limit pipe movement in the event of a longitudinal pipe break thus serving to control pipe whip inside containment.

The equipment hatch and air locks are supported entirely by the Containment Vessel and are not connected either directly or indirectly to any other structure. The equipment hatch was fabricated from welded steel and furnished with a double-gasketed flange and bolted dished door. Provision is made to pressure test the space between the double gaskets of its flange. Two personnel air locks are provided. Each personnel air lock is a double-door welded steel assembly. Provision is made to pressurize the air locks for periodic leakage rate tests.

The fuel transfer penetration provided is for fuel movement between the refueling cavity in the Containment Vessel and the spent fuel pool. This penetration consists of a 20-inch stainless steel pipe installed inside a 24-inch pipe. The inner pipe acts as the transfer tube. The outer pipe is welded to the Containment Vessel. Bellows expansion joints are provided between the two pipes to compensate for any differential movements. A double-gasketed blind flange is bolted on the refueling canal end of the transfer tube to seal the reactor containment. The end of the tube outside the containment is closed by a gate valve.

The ventilation system purge duct and make-up duct penetrations are welded directly to the penetration nozzles in a manner similar to the cold piping penetrations. The ducts are circular in cross-section and are designed to withstand the Containment Vessel maximum internal pressure. They are provided with isolation valves and blank flanges. The blank flanges were installed to increase the assurance that the penetration will be leak tight.

The relative motion between the Shield Building and the Containment Vessel is due to the Design Basis Accident (DBA) pressure and temperature growth of the Containment Vessel as well as the relative seismic displacements between the two structures. These relative displacements will affect only the bellows assembly, and are independent of any process line movements. Relative seismic displacements between the Containment Vessel and the Shield Building at the penetration elevations range from 0.032 to 0.148 inch for the Operating Basis Earthquake condition. The maximum DBA movement of the Containment Vessel resulting from both pressure and temperature is approximately 1.375 inch-radially and 0.687 inch-vertically. All of the relative displacements between both the Shield Building and process pipe and the Shield Building and the Containment Vessel have been considered in the design of the bellows assembly and the piping system.

The expansion joint bellows is attached at one end to the outer flue of the flued head and at the other end to the Containment Vessel penetration sleeve. The expansion joint is provided with a double layered bellows that has a connection between bellows for integrity testing. An impingement ring is mounted on the guard pipe to protect the expansion joint bellows from jet forces that might result from a pipe rupture inside containment. All bellows, including those associated with the fuel transfer tube, that are part of containment boundary, are fitted with protective covers which are removable for visual inspection.

The containment vessel and airlocks specifications required acceptance testing was carried out on the constructed Containment Vessel prior to installation of internals and penetrations. These tests included soap bubble tests at 5 psig and 41.4 psig, an over-pressure test at 51.8 psig, and an integrated leakage test at 41.4 psig. After successful completion of the initial soap bubble test, the pneumatic pressure structural test was performed on the Containment Vessel and each of the personnel airlocks at 51.8 psig. Both the inner and the outer doors of the personnel airlocks were tested at this pressure.

After placement of external support concrete, removal of temporary stiffeners, T-ring girder and pipe columns, and placement of internal support concrete (stiffener for the knuckle), but prior to fueling the reactor, the over-pressure test (at a pressure of 51.8 psig) was performed to provide assurance that removal of the stiffeners or other changes in the system during construction had not compromised the structural integrity of the Containment Vessel. This test was in accordance with the requirements of paragraph UG-100 of Division 1, Section VIII of the ASME B&PV Code.

Following the successful completion of the soap bubble and initial over-pressure tests, the leakage test at 46 psig pressure was performed on the Containment Vessel with the personnel airlock inner doors closed. The leakage rate was determined by the “Reference System Method” and confirmed by the “Absolute Method” results. The actual loss per 24 hours was less than 0.02 percent. On September 21, 1973, a report “Containment Vessel Strength Test - June 17, 1973,” was submitted to the NRC providing assurance that removal of the stiffeners or other changes during construction did not compromise the structural integrity of the containment vessel.

The containment systems and engineered safety features are described in detail in Chapters 5 and 6, respectively, of the PINGP USAR.

2.4 Containment / Shield Building Design Considerations Related to Leakage Testing

PINGP Units 1 and 2 are designed with features to mitigate potential post-Loss of coolant accident (LOCA) radiological releases to the environment. Containment radiological leakage is mitigated by the presence of two fission product barriers in series: the Containment Vessel and the Shield Building (often called the Annulus). This results in three major containment release paths:

- Auxiliary Building Special Ventilation Zone (ABSVZ) – Pipes connected to systems that are located in the Auxiliary Building Special Ventilation Zone. Containment leakage to the Auxiliary Building Special Ventilation Zone is treated by the Auxiliary Building Special Ventilation System (ABSVS) and released from the Shield Building vent stack.

- EXTERIOR – Pipes connected to systems that are exterior to the Shield Building and the Auxiliary Building Special Ventilation Zone. A small number of potential leakage paths could bypass the Shield Building Annulus and the Auxiliary Building Special Ventilation Zone. This leakage could potentially bypass both leakage collection zones and leak directly to the environment.

- ANNULUS – Penetrations that would leak to the Shield Building annulus following a LOCA. Containment leakage to the Shield Building is treated by the Shield Building Ventilation System (SBVS) and released from the Shield Building vent stack.

Separate tables are provided in Section 3.2.2 discussing the Type B and C leakage rate testing results reflecting leakage through these three different zones.

3.0 TECHNICAL EVALUATION

The following sections provide a discussion of 10 CFR 50, Appendix J testing requirements, reviews the PINGP Units 1 and 2 containment leakage licensing history and requirements, and reviews the PINGP Units 1 and 2 ILRT test results.

3.1 Justification for the Proposed TS Change

3.1.1 <u>Chronology of Testing Requirements of 10 CFR 50, Appendix J</u>

The testing requirements of 10 CFR 50, Appendix J, provide assurance that the leakage from the primary containment, including systems and components that penetrate the containment, shall not exceed the allowable leakage values specified within the TS. Also, 10 CFR 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.

10 CFR 50, Appendix J identifies three types of required tests: 1) Type A tests, intended to measure the overall integrated leakage rate of the primary containment; 2) Type B tests, intended to detect leakage paths and measure leakage across pressure containing or leakage limiting boundaries (other than valves) for primary reactor 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 50, Appendix J, was amended to add another approach, Option B, entitled “Performance-Based Requirements,” for performance of containment leakage testing. Option B requires the test intervals for Type A, Type B, and Type C testing to be determined 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. Use of the term “performance-based” within 10 CFR 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 was issued endorsing NEI 94-01, Revision 0, with certain modifications and additions. 10 CFR 50, Appendix J, Option B, in concert with the regulatory guide and the NEI guidance allows a licensee with a satisfactory ILRT performance history (i.e., two consecutive, successful Type A tests) to reduce the ILRT test frequency from three tests in 10 years to one test in 10 years. This relaxation was based on a NRC risk assessment provided in NUREG-1493, “Performance-Based Containment Leak-Test Program,” (Reference 8) and Electric Power Research Institute (EPRI) topical report TR-104285, “Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals,” (Reference 9) both of which showed that the increase in risk associated with extending the ILRT surveillance interval was very small.

In October 2008, NEI 94-01, Revision 2-A was issued. The NRC indicated in the SE for NEI 94-01, Revision 2, that this report describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J. Section 4.0 of the NRC SE for NEI 94-01, Revision 2, provides specific limitations and conditions for utilization of the report. NEI 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 increasing the duration of the interval included industry performance data, plant-specific performance data, and risk insights.

In Subsection 3.1.1.2, "Deferral of Tests Beyond The 15-Year Interval," of the NRC SE for the NEI 94-01, Revision 2 the NRC staff provided the following guidance concerning the use of test interval extensions (which was later augmented by additional guidance in Regulatory Issue Summary (RIS) 2008-27 (Reference 10)):(1)

> … 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 NEI 94-01, Revision 2 the licensee will have to demonstrate to the NRC staff that an unforeseen emergent condition exists.

In July 2012, NEI 94-01, Revision 3-A was issued. This document describes an acceptable approach for implementing the optional performance-based requirements of Option B to 10 CFR 50, Appendix J and includes provisions for extending Type A ILRT intervals to up to 15 years and for extending Type B and C test frequencies. NEI 94-01, Revision 3 has been endorsed by an NRC SE on May 8, 2012, (Reference 1) as an acceptable methodology for complying with the provisions of Option B to 10 CFR 50, Appendix J. The regulatory positions stated in RG 1.163 as modified by NRC SEs dated 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.

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1. RIS 2008-27, "Staff Position on Extension of the Containment Type A Test Interval Beyond 15 Years Under Option B of Appendix J to 10 CFR Part 50"

3.1.2 Current PINGP Unit 1 and 2 Integrated Leakage Rate Testing Requirements

10 CFR 50, Appendix J was revised to allow licensees to choose containment leakage testing under either Option A, “Prescriptive Requirements,” or Option B, “Performance-Based Requirements.” On February 19, 1997, the NRC approved License Amendment Nos. 126 and 118 for PINGP Units 1 and 2 (Reference 11) authorizing the implementation of Option B for containment leakage system tests.

Current TS 5.5.14 requires that a program be established to comply with the containment leakage rate testing requirements of 10 CFR 50.54(o) and 10 CFR 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 10 CFR 50, Appendix J, Option B.

RG 1.163, Section C.1 states that licensees intending to comply with 10 CFR 50, Appendix J, Option B, should establish test intervals based upon the criteria in Section 11.0 of NEI 94-01 [Revision 0], rather than using the test intervals specified in ANSI/ANS 56.8-1994. NEI 94-01, Revision 0, Section 11.0 refers to Section 9.0, which states that Type A testing shall be performed during a period of reactor shutdown at a frequency of at least once per 10 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 1.0 L_a (where L_a is the maximum allowable leakage rate at design pressure). The 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 10 CFR 50, Appendix J, Option B performance based containment leakage rate testing program altered the frequency of measuring primary containment leakage in the Type 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 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, Revision 0, is based, in part, upon a generic evaluation documented in NUREG-1493. The evaluation documented in NUREG-1493 included a study of the dependence of reactor accident risks on containment leak tightness for differing types of containments, including a Pressurized Water Reactor (PWR), i.e., Surry, with a containment design similar to that for the PINGP Units 1 and 2 containment structures. Section 10.1.2 of NUREG-1493 concluded that reducing the frequency of Type A tests from the original three tests per 10 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 performance of ILRTs is possible with a minimal impact on public risk.

3.1.3 PINGP Units 1 and 2 – 10 CFR 50, Appendix J, Option B Licensing History

a. License Amendment Nos. 62 and 56 (February 23, 1983) (Reference 12)

The TS were revised to reflect NRC review of Northern States Power proposals to comply with the requirements of 10 CFR 50, Appendix J. Provisions were added to reduce the 24 hour containment leak rate testing period, delete obsolete leak test requirements for the Shield and Auxiliary Buildings, and increase the allowable leakage rate for the overall airlock door tests.

b. Exemption to 10 CFR 50, Appendix J to Permit Use of Mass-Point Method to Calculate Containment Leak Rates (September 27, 1988) (Reference 13)

Approved an exemption from Paragraph III.A.3 of 10 CFR 50, Appendix J, to permit the use of the Mass-Point method to calculate containment leakage rates.

c. License Amendment Nos. 117 and 110 (April 18, 1995) (Reference 14)

Approved an amendment revising the frequency of the TS Containment Integrated Leak Rate Test subject to the provisions of 10 CFR 50, Appendix J, as modified by approved exemptions.

d. License Amendment Nos. 126 and 118 (February 19, 1997) (Reference 15)

Authorized implementation of 10 CFR 50, Appendix J – Option B for containment leakage system tests.

e. Unit 1 License Amendment No. 165 (August 20, 2004) (Reference 16)

Revised TS 5.5.14 to perform post-modification testing, scheduled for fall 2004, of the containment pressure boundary following PINGP Unit 1 steam generator replacement in accordance with the ASME B&PV Code, Section XI, instead of 10 CFR Part 50, Appendix J, Option B.

f. License Amendment Nos. 174 and 164 (October 2, 2006) (Reference 17)

Revised TS 5.5.14 for PINGP Units 1 and 2 to allow a one-time interval extension of no more than 5 years for performance of the ILRTs.

g. <u>License Amendment Nos. 206 and 193 (January 22, 2013) (Reference 18)</u>

Approved Alternative Source Term (AST) for PINGP Units 1 and 2.

h. <u>Unit 2 License Amendment No. 197 (September 11, 2013) (Reference 19)</u>

Revised TS 5.5.14 to provide an exception from performing an ILRT following modifications to the containment pressure boundary resulting from replacement of Unit 2 steam generators in the fall of 2013.

3.2 Leak Rate Test History

TS 5.5.14 currently requires that Type A, Type B, and Type C testing be performed in accordance with RG 1.163, which endorses the methodology for complying with Option B of 10 CFR 50, Appendix J. 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.

The total ILRT history for PINGP Units 1 and 2 is provided in the following section. Subsequent sections provide the results from the fall of 2002 through fall 2018 for Type B testing (leakage limiting boundaries other than valves) and for Type C testing (containment isolation valve leakage).

3.2.1 <u>Integrated Leak Rate Testing History (Type A Testing)</u>

The total ILRT test history for PINGP Units 1 and 2 is provided in the following four tables. The first two tables provide historical Type A test results from the time of initial licensing of PINGP Units 1 and 2 up to the September 1988 and April 1989 Type A test performances, respectively. The second two tables provide the results of the more current ILRTs for the PINGP Units 1 and 2.

A pre-operational test and the two most recent ILRTs for each unit were conducted at the design pressure of 46 psig. The original 10 CFR 50, Appendix J regulation allowed reduced pressure testing and the following tests were performed at 23 psig (half the design pressure) with reduced pressure acceptance criteria based upon full pressure acceptance criteria. In 1995, 10 CFR 50, Appendix J was revised to provide Option B, which does not allow reduced pressure testing. NSPM received approval to implement 10 CFR 50, Appendix J – Option B via Amendments 126 and 118 for PINGP Units 1 and 2 on February 19, 1997. These amendments removed the authorization to perform reduced pressure ILRT testing from the PINGP Units 1 and 2 TS. Subsequent ILRTs were performed assuming the full containment design pressure.

Table 1 – PINGP Unit 1 Historical Type A ILRT Results

Test Completion Date	Test Pressure (psig)	95% Upper Confidence Limit (UCL) (weight-percent/day)
July 4, 1973	46	0.0234
July 4, 1973	23	0.0189
April 15, 1977	23	0.0386
October 9, 1980	23	0.0806
February 20, 1985	23	0.0247
September 18, 1988	23	0.0450

Table 2 – PINGP Unit 2 Historical Type A ILRT Results

Test Completion Date	Test Pressure (psig)	95% UCL (weight-percent/day)
August 1, 1974	46	0.0156
August 1, 1974	23	0.0257
December 5, 1977	23	0.0628
March 27, 1981	23	0.0206
October 16, 1985	23	0.0402
April 21, 1989	23	0.0272

The results of the last four ILRTs for PINGP Unit 1 and the last three ILRTs for PINGP Unit 2 are shown in the following two tables, respectively.

The following definitions apply to Tables 3 and 4:

L_a = DBA Leakage Rate at accident pressure (P_a) 46 psig = 0.15% of containment air weight per day. L_a was 0.25% of containment air weight per day prior to January 22, 2013.

L_T = Maximum Allowable Test Leakage Rate at reduced rest pressure (23 psig). This allowance was removed when 10 CFR 50, Appendix J, Option B was

implemented.

Table 3 – PINGP Unit 1 Recent Type A ILRT Results

Test Date	Test Press. (psig)	Design Press. (psig)	As-Found (weight-percent/day)			As-Left (weight-percent/day)		
			Leak Rate	TS Acceptance Criteria		Leak Rate	TS Acceptance Criteria	
June 21, 1991	23	46	0.0667	0.11569	0.75 L_T	0.0597	0.11569	0.75 L_T
June 24, 1994	23	46	0.0998	0.11569	0.75 L_T	0.0772	0.11569	0.75 L_T
December 1, 1997	46	46	0.0413	0.25	1.0 L_a	0.0445	0.1875	0.75 L_a
October 31, 2012	46	46	0.0116	0.25	1.0 L_a	0.0173	0.1875	0.75 L_a

Table 4 – PINGP Unit 2 Recent Type A ILRT Results

Unit 2 Recent Type A ILRT Results								
Test Date	Test Press. (psig)	Design Press. (psig)	As-Found (weight-percent/day)			As-Left (weight-percent/day)		
			Leak Rate	TS Acceptance Criteria		Leak Rate	TS Acceptance Criteria	
January 1, 1993	23	46	0.0307	0.13258	0.75 L_T	0.0158	0.13258	0.75 L_T
March 5, 1997	46	46	0.0435	0.25	1.0 L_a	0.0418	0.1875	0.75 L_a
March 1, 2012	46	46	0.0284	0.25	1.0 L_a	0.0288	0.1875	0.75 L_a

As required by NEI 94-01, Revision 3-A, Section 9.1.2, further extensions in test intervals are based upon two consecutive, periodic, successful, Type A tests and the requirements stated in Section 9.2.3 of that guideline. The As-Found leakage for these Type A test performances are well within the maximum allowable containment (As-Found) leakage rate specified in TS 5.5.14.c of 0.15 weight-percent/day. Therefore, the requirement to demonstrate an acceptable performance history in order to place a plant on an extended interval in accordance with NEI 94-01, Revision 3-A (i.e., successful completion of two consecutive periodic Type A tests) has been consecutively met over the last several ILRT test intervals. As a result, PINGP Units 1 and 2 are each eligible to be placed on an extended ILRT frequency (performance of a Type A test at least once per 15 years). The current ILRT interval frequency for PINGP Units 1 and 2 is once per 10 years.

Repair or replacement activities (including any unplanned activities) performed on the pressure retaining boundary of the primary containment prior to the next scheduled Type A test are subject to the leakage test requirements of ASME B&PV Code

(ASME Code) Section XI, Paragraph IWE-5221, "Leakage Test." There have been no pressure or temperature excursions in the containment that could have adversely affected containment integrity. There is no anticipated addition or removal of plant hardware within containment that could affect leak-tightness that would not be challenged by local leak rate testing.

3.2.2 Type B and C Testing

Leakage Pathways

The PINGP Unit 1 and Unit 2 Type B and C Leakage Rate Summation History tables below are comprised of three different zones: the Auxiliary Building Special Ventilation Zone (ABSVZ), the Exterior Zone of containment, and the containment Annulus. Section 2.4 of this enclosure discusses each of these three zones. The ABSVZ and the Exterior Zone have leakage rate limits specified within the TS. The Annulus does not have a separate TS specified leakage limit, so Annulus leakage is included in the leakage summation together with that from the ABSVZ and Exterior Zone of containment and is compared against $0.6L_a$.

On January 22, 2013, the NRC approved Amendments 206 and 193, for PINGP Units 1 and 2, respectively, which modified the PINGP licensing basis and TS to reflect adoption of the AST methodology. With AST implementation, the allowable TS L_a was reduced going forward.

The allowable total leakage for the ABSVZ before AST was less than 0.1 weight-percent per 24 hours at 46 psig (<103,200 standard cubic centimeters per minute (sccm)). The current allowable total leakage for the ABSVZ is less than 0.06 weight-percent per 24 hours at 46 psig (<61,920 sccm). The allowable Exterior Zone to containment total leakage before AST was less than 0.01 weight-percent per 24 hours at 46 psig (<10,320 sccm). The current allowable Exterior Zone total leakage after AST is less than 0.006 weight-percent per 24 hours at 46 psig (<6,192 sccm). As previously stated, the Annulus does not have a specified TS leakage limit, so the leakage is compared to the percentage of $0.6L_a$.

The following tables show the as-found minimum and as-left maximum leakage values for the Auxiliary Building Special Ventilation Zone, the Exterior Zone of containment, and the containment Annulus.

The allowable total leakage for each of these three zones (i.e., the ABSVZ, the Exterior Zone of containment, and the Annulus) decreased with adoption of AST. The results in the "TS Percentage" column in the following tables show the percentage of leakage against the applicable TS allowable at the time, either pre-AST (blue) or post-AST (orange). The results in the "Percentage of" column in the following tables show all of the results against the current TS value (post-AST).

As can readily be seen, the Type B and Type C test results show a large amount of margin between the actual as-found and the as-left outage summations and the respective TS leakage rate acceptance criteria (i.e., less than 0.6 L_a in the first case for Tables 5 and 6).

Additional tables were developed for Type B and Type C testing documenting the Type B and Type C penetrations that are currently on extended frequencies from the results of the most recent two tests.

- The as-found minimum pathway leak rate for PINGP Unit 1 shows an average of 8.8 percent of 0.6 L_a.
- The as-left maximum pathway leak rate for PINGP Unit 1 shows an average of 12.8 percent of 0.6 L_a with a high of 18.0 percent or 10.8 percent of L_a.

Table 5 – PINGP Unit 1 Type B and C Leakage Rate Summation History

(Test Allowable ($0.6L_a$) is 154800 sccm Prior to 2013)
(Test Allowable ($0.6L_a$) is 92880 sccm 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	**TS Percentage of $0.6L_a$**	**Percentage of $0.6L_a$ (92880 sccm)**	**(sccm)**	**TS Percentage of $0.6L_a$**	**Percentage of $0.6L_a$ (92880 sccm)**
1R22 (Fall 2002)	12,850	8.3%	13.8%	12,920	8.4%	13.9%
1R23 (Fall 2004)	17,644	11.4%	19.0%	21,125	13.7%	22.8%
1R24 (Spring 2006)	15,173	9.8%	16.3%	16,527	10.7%	17.8%
1R25 (Spring 2008)	6,859	4.4%	7.4%	13,679	8.8%	14.7%
1R26 (Fall 2009)	12,752	8.2%	13.7%	16,638	10.8%	17.9%
1R27 (Spring 2011)	8,437	5.5%	9.1%	17,292	11.2%	18.6%
1R28 (Fall 2012)	7,817	5.1%	8.4%	27,836	18.0%	30.0%
1R29 (Fall 2014)	8,511	9.2%	9.2%	13,921	15.0%	15.0%
1R30 (Fall 2016)	12,516	13.5%	13.5%	13,911	15.0%	15.0%
1R31 (Fall 2018)	11,589	12.5%	12.5%	15,768	17.0%	17.0%
	AVERAGE	**8.8 %**	**12.3%**	**AVERAGE**	**12.8%**	**18.3%**
	HI % L_a	**8.1%**	**11.4%**	**HI % L_a**	**10.8%**	**18.0%**

sccm = standard cubic centimeters per minute

- The as-found minimum pathway leak rate for PINGP Unit 2 shows an average of 4.2 percent of 0.6 L_a.
- The as-left maximum pathway leak rate for PINGP Unit 2 shows an average of 7.3 percent of 0.6 L_a with a high of 15.4 percent or 9.3 percent of L_a.

Table 6 – PINGP Unit 2 Type B and C Leakage Rate Summation History

(Test Allowable ($0.6L_a$) is 154800 SCCM Prior to 2013)
(Test Allowable ($0.6L_a$) is 92880 SCCM 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	**TS Percentage of $0.6L_a$**	**Percentage of $0.6L_a$ (92880 sccm)**	**(sccm)**	**TS Percentage of $0.6L_a$**	**Percentage of $0.6L_a$ (92880 sccm)**
2R22 (Fall 2003)	14,085	9.1%	15.2%	9,777	6.3%	10.5%
2R23 (Spring 2005)	8,824	5.7%	9.5%	23,846	15.4%	25.7%
2R24 (Fall 2006)	6,066	3.9%	6.5%	6,321	4.1%	6.8%
2R25 (Fall 2008)	5,027	3.3%	5.4%	10,857	7.0%	11.7%
2R26 (Spring 2010)	5,230	3.4%	5.6%	7,080	4.6%	7.6%
2R27 (Spring 2012)	5,497	3.6%	5.9%	5,625	3.6%	6.1%
2R28 (Fall 2013)	4,644	5.0%	5.0%	5,634	6.1%	6.1%
2R29 (Fall 2015)	3,188	3.4%	3.4%	5,431	5.9%	5.9%
2R30 (Fall 2017)	5,112	5.5%	5.5%	11,007	11.9%	11.9%
	AVERAGE	**4.2 %**	**5.9%**	**AVERAGE**	**7.3%**	**10.2%**
	HI % L_a	**5.5%**	**9.1%**	**HI % L_a**	**9.3%**	**15.4%**

sccm = standard cubic centimeters per minute

- For PINGP Unit 1, there have been no LLRT failures in the past 36 months (two outages).

- For PINGP Unit 2, two penetrations had exceeded the administrative limit and one penetration had a test failure in the past 48 months (two outages). All conditions were repaired and had satisfactory as-left leakage rate tests. Details of the specific conditions are in Table 17.

Following satisfactory performance of two consecutive as-found LLRTs, these penetrations will return to an extended testing frequency.

Table 7 – PINGP Unit 1 ABSVZ Leakage History

(Test Allowable ($0.06L_a$) is 103,200 sccm Prior to 2013)
(Test Allowable ($0.06L_a$) is 61,920 sccm 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	TS Percentage of $0.06L_a$	Percentage of $0.06L_a$ (61920 sccm)	(sccm)	TS Percentage of $0.06L_a$	Percentage of $0.06L_a$ (61920 sccm)
1R22 (Fall 2002)	9,810	9.5%	15.9%	10,110	9.8%	16.3%
1R23 (Fall 2004)	15,758	15.3%	25.5%	19,144	18.6%	30.9%
1R24 (Spring 2006)	12,905	12.5%	20.9%	12,186	11.8%	19.7%
1R25 (Spring 2008)	4,600	4.5%	7.4%	6,973	6.8%	11.3%
1R26 (Fall 2009)	10,976	10.6%	17.7%	13,830	13.4%	22.3%
1R27 (Spring 2011)	5,847	5.7%	9.5%	8,154	7.9%	13.2%
1R28 (Fall 2012)	5,396	5.2%	8.7%	22,168	21.5%	35.8%
1R29 (Fall 2014)	6,089	9.8%	9.8%	8,330	13.5%	13.5%
1R30 (Fall 2016)	6,687	10.8%	10.8%	7,062	11.4%	11.4%
1R31 (Fall 2018)	6,763	10.9%	10.9%	6,302	10.2%	10.2%
	Average	**9.5%**	**13.7%**	**Average**	**12.5%**	**18.5%**
	High % L_a	**0.9%**	**1.5%**	**High % L_a**	**1.3%**	**2.1%**

sccm = standard cubic centimeters per minute

Table 8 – PINGP Unit 2 ABSVZ Leakage History

(Test Allowable ($0.06L_a$) is 103,200 sccm Prior to 2013)
(Test Allowable ($0.06L_a$) is 61,920 sccm 2013 to Present)

Refueling Outage	**As-Found Minimum Pathway Leakage**			**As-Left Maximum Pathway Leakage**		
	(sccm)	**TS Percentage of $0.06L_a$**	**Percentage of $0.06L_a$ (61920 sccm)**	**(sccm)**	**TS Percentage of $0.06L_a$**	**Percentage of $0.06L_a$ (61920 sccm)**
2R22 (Fall 2003)	12,149	11.8%	19.6%	7,123	6.9%	11.5%
2R23 (Spring 2005)	5,953	5.8%	9.6%	16,317	15.8%	26.4%
2R24 (Fall 2006)	3,810	3.7%	6.2%	3,826	3.7%	6.2%
2R25 (Fall 2008)	4,200	4.1%	6.8%	5,431	5.3%	8.8%
2R26 (Spring 2010)	3,859	3.7%	6.2%	4,355	4.2%	7.0%
2R27 (Spring 2012)	3,430	3.3%	5.5%	3,745	3.6%	6.1%
2R28 (Fall 2013)	3,164	5.1%	5.1%	4,257	6.9%	6.9%
2R29 (Fall 2015)	1,236	2.0%	2.0%	1,907	3.1%	3.1%
2R30 (Fall 2017)	1,235	2.0%	2.0%	4,492	7.3%	7.3%
	Average	**3.7%**	**5.4%**	**Average**	**6.2%**	**9.0%**
	High % L_a	**0.7%**	**1.2%**	**High % L_a**	**0.9%**	**1.6%**

sccm = standard cubic centimeters per minute

Table 9 – PINGP Unit 1 Exterior Leakage History

(Test Allowable ($0.006L_a$) is 10,320 sccm Prior to 2013)
(Test Allowable ($0.006L_a$) is 6,192 sccm 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	**TS Percentage of $0.006L_a$**	**Percentage of $0.006L_a$ (6192 sccm)**	**(sccm)**	**TS Percentage of $0.006L_a$**	**Percentage of $0.006L_a$ (6192 sccm)**
1R22 (Fall 2002)	285	2.8%	4.6%	360	3.5%	5.8%
1R23 (Fall 2004)	486	4.7%	7.9%	360	3.5%	5.8%
1R24 (Spring 2006)	477	4.6%	7.7%	497	4.8%	8.0%
1R25 (Spring 2008)	249	2.4%	4.0%	664	6.4%	10.7%
1R26 (Fall 2009)	81	0.8%	1.3%	609	5.9%	9.8%
1R27 (Spring 2011)	395	3.8%	6.4%	6,498	63.0%	105.0%
1R28 (Fall 2012)	329	3.2%	5.3%	667	6.5%	10.8%
1R29 (Fall 2014)	692	11.2%	11.2%	2,338	37.8%	37.8%
1R30 (Fall 2016)	110	1.8%	1.8%	796	12.9%	12.9%
1R31 (Fall 2018)	250	4.0%	4.0%	1,743	28.2%	28.2%
	Average	**3.9%**	**5.4%**	**Average**	**17.2%**	**23.5%**
	High % L_a	**0.1%**	**0.1%**	**High % L_a**	**0.4%**	**0.6%**

sccm = standard cubic centimeters per minute

Table 10 – PINGP Unit 2 Exterior Leakage History

(Test Allowable ($0.006L_a$) is 10,320 sccm Prior to 2013)
(Test Allowable ($0.006L_a$) is 6,192 sccm 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	TS Percentage of $0.006L_a$	Percentage of $0.006L_a$ (6192 sccm)	(sccm)	TS Percentage of $0.006L_a$	Percentage of $0.006L_a$ (6192 sccm)
2R22 (Fall 2003)	370	3.6%	6.0%	370	3.6%	6.0%
2R23 (Spring 2005)	240	2.3%	3.9%	4,962	48.1%	80.1%
2R24 (Fall 2006)	437	4.2%	7.1%	437	4.2%	7.1%
2R25 (Fall 2008)	113	1.1%	1.8%	795	7.7%	12.8%
2R26 (Spring 2010)	173	1.7%	2.8%	429	4.2%	6.9%
2R27 (Spring 2012)	164	1.6%	2.7%	230	2.2%	3.7%
2R28 (Fall 2013)	104	1.7%	1.7%	218	3.5%	3.5%
2R29 (Fall 2015)	340	5.5%	5.5%	847	13.7%	13.7%
2R30 (Fall 2017)	362	5.9%	5.9%	436	7.0%	7.0%
	Average	**3.0%**	**3.9%**	**Average**	**11.3%**	**15.7%**
	High % L_a	**0.04%**	**0.04%**	**High % L_a**	**0.3%**	**0.5%**

sccm = standard cubic centimeters per minute

Table 11 – PINGP Unit 1 Annulus Leakage History

(Test Allowable ($0.6L_a$) is 154,800 sccm Prior to 2013)
(Test Allowable ($0.6L_a$) is 92,880 sccm 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	**TS Percentage of $0.6L_a$**	**Percentage of $0.6L_a$ (92880 sccm)**	**(sccm)**	**Percentage of $0.6L_a$**	**Percentage of $0.6L_a$ (92880 sccm)**
1R22 (Fall 2002)	2,755	1.8%	3.0%	2,450	1.6%	2.6%
1R23 (Fall 2004)	1,400	0.9%	1.5%	1,621	1.1%	1.8%
1R24 (Spring 2006)	1,791	1.2%	1.9%	3,844	2.5%	4.1%
1R25 (Spring 2008)	2,010	1.3%	2.2%	6,042	3.9%	6.5%
1R26 (Fall 2009)	1,695	1.1%	1.8%	2,199	1.4%	2.4%
1R27 (Spring 2011)	2,195	1.4%	2.4%	2,640	1.7%	2.9%
1R28 (Fall 2012)	2,092	1.4%	2.3%	5,001	3.2%	5.4%
1R29 (Fall 2014)	1,730	1.9%	1.9%	3,253	3.5%	3.5%
1R30 (Fall 2016)	5,719	6.2%	6.2%	6,053	6.5%	6.5%
1R31 (Fall 2018)	4,576	4.9%	4.9%	7,723	8.3%	8.3%
	Average	**2.2%**	**2.8%**	**Average**	**3.4%**	**4.4%**
	High % L_a	**3.70%**	**3.70%**	**High % L_a**	**4.99%**	**4.99%**

sccm = standard cubic centimeters per minute

Table 12 – PINGP Unit 2 Annulus Leakage History

(Test Allowable ($0.6L_a$) is 154,800 sccm Prior to 2013)
(Test Allowable ($0.6L_a$) is 92,880 sccm 2013 to Present)

Refueling Outage	As-Found Minimum Pathway Leakage			As-Left Maximum Pathway Leakage		
	(sccm)	TS Percentage of $0.6L_a$	Percentage of $0.6L_a$ (92880 sccm)	(sccm)	Percentage of $0.6L_a$	Percentage of $0.6L_a$ (92880 sccm)
2R22 (Fall 2003)	1,566	1.0%	1.7%	2,284	1.5%	2.5%
2R23 (Spring 2005)	2,631	1.7%	2.8%	2,566	1.7%	2.8%
2R24 (Fall 2006)	1,819	1.2%	2.0%	2,058	1.3%	2.2%
2R25 (Fall 2008)	714	0.5%	0.8%	4,631	3.0%	5.0%
2R26 (Spring 2010)	1,198	0.8%	1.3%	2,296	1.5%	2.5%
2R27 (Spring 2012)	1,903	1.2%	2.1%	1,650	1.1%	1.8%
2R28 (Fall 2013)	1,376	1.5%	1.5%	1,159	1.3%	1.3%
2R29 (Fall 2015)	1,612	1.7%	1.7%	2,677	2.9%	2.9%
2R30 (Fall 2017)	3,515	3.8%	3.8%	6,080	6.6%	6.6%
	Average	**1.5%**	**2.0%**	**Average**	**2.4%**	**3.1%**
	High % L_a	**2.27%**	**2.27%**	**High % L_a**	**3.93%**	**3.93%**

sccm = standard cubic centimeters per minute

Extension of Type B and C Testing

There are performance factors that need to be considered before applying an extended testing interval. For the purposes of determining an extended test interval, an assessment of the containment penetration and valve performance has been performed and documented. The following items are considered in establishing and implementing extended test intervals for Type B and C components:

- Past Component Performance – Specific component performance of two successful consecutive as-found Type B or C tests are performed.
- Service – The environment and use of components in determining their likelihood of failure based on their performance history.

- Design – Valve type and penetration design may contribute to their leakage characteristics.
- Safety Impact – The relative importance of penetrations due to the potential impact of failure in limiting releases from containment under accident conditions.
- Cause Determination – For failures identified during an extended test interval, a cause determination should be conducted and appropriate corrective actions identified to address common-mode failure mechanisms.

For Type B testing, 19 penetrations for PINGP Unit 1 and 18 penetrations for PINGP Unit 2 are currently on extended test frequency. For both PINGP Units 1 and 2, as-left testing is performed when the penetrations are opened. If these penetrations are not opened for multiple outages, the penetrations are eligible for extended frequency testing. Measured leakage for these penetrations has not changed significantly over 120 months.

For Type C testing, there are 16 penetrations for PINGP Unit 1 and 14 penetrations for PINGP Unit 2 that are currently on extended frequency. The percentage of eligible penetrations currently on extended frequency supports an extended test interval to up to 75 months for Type C tested CIVs, in accordance with the guidance of NEI 94-01, Revision 3-A. The Vent and Purge valves have been modified to include blind flanges inside containment. The number of penetrations on extended frequency is adjusted periodically based on valve performance and other plant testing requirements.

Table 13 – PINGP Units 1 and 2 Extended Frequency Percentages

Group	Number of Penetrations	Number of Penetrations on Extended Frequency	Percent Extended	Comment
Unit 1				
Type B Penetrations	28	19	70.0%	10 Penetrations are Bellows
Type C Penetrations	28	16	60.0%	Maximum extended frequency is 60 months
Unit 2				
Type B Penetrations	28	18	64.3%	10 Penetrations are Bellows
Type C Penetrations	28	14	57.1%	Maximum extended frequency is 60 months

For Type B testing, Table 14 for Unit 1 and Table 15 for Unit 2, respectively, document the most recent two tests. The number of penetrations on extended frequency is adjusted periodically based on performance and other plant testing requirements.

Table 14 – PINGP Unit 1 Type B Penetrations on Extended Frequency Percentages

Pen No.	Description	Limit (sccm)	Most Recent Test	Leakage (sccm)	Previous Test	Leakage (sccm)
6A	Main Steam Loop A Bellows	300	1R28	10	1R25	60
6B	Main Steam Loop B Bellows	300	1R29	48	1R24	60
7A	Main Feedwater Loop A Bellows	300	1R31	42	1R27	2
7B	Main Feedwater Loop B Bellows	300	1R30	8	1R26	25
8A	11 Steam Generator Blowdown Bellows	300	1R30	24	1R26	45
8B	12 Steam Generator Blowdown Bellows	300	1R31	26	1R27	3
9	RHR Loop Out Bellows	300	1R28	3	1R24	60
10	RHR In Bellows	300	1R31	28	1R27	4
11	Letdown Line Bellows	300	1R28	123	1R24	210
18	Fuel Transfer Tube Bellows	300	1R31	31	1R27	3
25A	Containment Purge Exhaust	300	1R30	3	1R29	2
25B	Containment Purge Supply	300	1R30	1	1R29	4
27C1	ILRT Pressure Sensing Line	300	1R31	200	1R30	0
27C2	ILRT Pressure Sensing Line	300	1R31	11	1R30	165
34	Electrical Penetrations	3000	1R31	1,528	1R30	1,117
42C	Heating Steam Supply	300	1R30	50	1R29	13
42F1	Heating Steam Condensate Return	300	1R31	16	1R30	4
42F2	Heating Steam Return Vent	300	1R31	9	1R30	7
EH	Equipment Hatch	300	1R31	6	1R30	6

Table 15 – PINGP Unit 2 Type B Penetrations on Extended Frequency Percentages

Pen No.	Description	Limit (SCCM)	Most Recent Test	Leakage (SCCM)	Previous Test	Leakage (SCCM)
6C	Main Steam Loop A Bellows	300	2R28	41	2R25	5
6D	Main Steam Loop B Bellows	300	2R29	15	2R26	3
7C	Main Feedwater Loop A Bellows	300	2R28	0	2R25	8
7D	Main Feedwater Loop B Bellows	300	2R28	13	2R24	60
8C	21 Steam Generator Blowdown Bellows	300	2R29	14	2R26	1
8D	22 Steam Generator Blowdown Bellows	300	2R29	15	2R26	5
9	RHR Loop Out Bellows	300	2R30	18	2R27	2
10	RHR In Bellows	300	2R30	18	2R27	10
11	Letdown Line Bellows	300	2R28	10	2R24	60
18	Fuel Transfer Tube Bellows	300	2R28	39	2R24	60
25A	Containment Purge Exhaust	300	2R30	2	2R29	0
25B	Containment Purge Supply	300	2R30	2	2R28	0
27C1	ILRT Pressure Sensing Line	300	2R30	0	2R29	9
27C2	ILRT Pressure Sensing Line	300	2R30	0	2R29	14
34	Electrical Penetrations	3000	2R30	3347 (Note 1)	2R29	273
42E1	Heating Steam Condensate Return	300	2R29	0	2R27	1
42E2	Heating Steam Condensate Vent	300	2R29	1	2R27	2
54	Heating Steam Supply	300	2R29	0	2R25	5
EH	Equipment Hatch	300	2R30	3	2R29	20

Note 1: The as-found leakage for Penetration 34 was 3,347 sccm, which exceeded the administrative limit due to a loose union connection on one electrical penetration assembly. The connection was tightened and the as-left leakage test for the electrical penetration was completed satisfactory (1,967 sccm).

For Type C testing the following two tables (Table 14 for Unit 1 and Table 15 for Unit 2) document the most recent two tests. The number of penetrations on extended frequency is adjusted periodically based on valve performance and other plant testing requirements.

Table 16 – PINGP Unit 1 Type C Penetrations on Extended Frequency – Most Recent Two Tests (Maximum Pathway As-Found Leakage)

Pen No.	Description	Valve(s)	Limit (sccm)	Most Recent Test	Leakage (sccm)	Previous Test	Leakage (sccm)
1	PRT Sample to Gas Analyzer	CV-31318 CV-31319	1000	1R31	5	1R29	5
4	Primary System Vent Header	CV-31434 CV-31435	1000	1R31	15	1R30	1
5	RCD Pump Discharge	CV-31436 CV-31437	2000	1R31	656	1R29	2
11	Letdown Line	CV-31325 CV-31326 CV-31327 CV-31339	3000	1R31	220	1R30	86
14	11 and 12 RCP Seal Water Return	MV-32166 MV-32199	2000	1R31	60	1R30	0
15	Pressurizer Steam Sample	MV-32400 MV-32401	1000	1R31	186	1R29	5
16	Pressurizer Liquid Sample	MV-32402 MV-32403	1000	1R30	1	1R28	1
17	Hot Leg Loop B Sample	MV-32404 MV-32405	1000	1R30	6	1R29	0
21	RCDT to Gas Analyzer	CV-31545 CV-31546	1000	1R31	20	1R29	15
22	Containment Air Sample In	CV-31022 CV-31092	1000	1R31	968	1R30	2
23	Containment Air Sample Out	CV-31019 CV-31750	1000	1R31	23	1R29	10
26	Sump A Discharge	CV-31438 CV-31439	2000	1R31	0	1R30	10
29A	Containment Spray	CS-12 CS-19 CS-26-1 CS-26-3 MV-32105	5500	1R31	1775	1R30	2400
29B	Containment Spray	CS-11 CS-18 CS-26-2 CS-26-4 MV-32103	5500	1R31	762	1R30	832
31	N_2 to Accumulators	CV-31242 CV-31440 CV-31441 CV-31444	4000	1R30	8	1R29	5
35	SI and Accumulator Test Line	SI-20-16 SI-35-25	1000	1R30	0	1R29	7

Table 17 – PINGP Unit 2 Type C Penetrations on Extended Frequency – Most Recent Two Tests (Maximum Pathway As-Found Leakage)

Pen. No.	Description	Valve(s)	Limit (sccm)	Most Recent Test	Leakage (sccm)	Previous Test	Leakage (sccm)
1	PRT Sample to Gas Analyzer	CV-31344 CV-31345	1000	2R29	10	2R28	3
4	Primary System Vent Header	CV-31733 CV-31734	1000	2R30	3	2R28	0
5	RCD Pump Discharge	CV-31735 CV-31736	2000	2R30	892	2R29	8780 (Note 1)
11	Letdown Line	CV-31347 CV-31348 CV-31349 CV-34130	3000	2R29	390	2R28	30
14	11 and 12 RCP Seal Water Return	MV-32194 MV-32210	2000	2R30	78660 (Note 2)	2R29	14
15	Pressurizer Steam Sample	MV-32406 MV-32407	1000	2R30	1	2R28	1
16	Pressurizer Liquid Sample	MV-32408 MV-32409	1000	2R30	3	2R29	0
17	Hot Leg Loop B Sample	MV-32410 MV-32411	1000	2R30	6	2R29	0
21	RCDT to Gas Analyzer	CV-31731 CV-31732	1000	2R30	20	2R28	29
22	Containment Air Sample In	CV-31129 CV-31644	1000	2R30	2	2R29	3
23	Containment Air Sample Out	CV-31642 CV-31643	1000	2R30	2	2R29	0
26	Sump A Discharge	CV-31619 CV-31620	2000	2R29	6	2R28	0
29A	Containment Spray	CS-42 CS-49 2CS-26-1 2CS-26-3 MV-32114	5500	2R30	445	2R29	237
29B	Containment Spray	CS-41 CS-48 2CS-26-2 2CS-26-4 MV-32116	5500	2R30	601	2R29	707
31	N_2 to Accumulators	CV-31244 CV-31511 CV-31512 CV-31554	4000	2R29	11	2R28	0
35	SI and Accumulator Test Line	2SI-20-16 2SI-35-25	1000	2R29	1	2R28	73

Note 1: CV-31736 (CIV) exceeded the administrative limit due to the leakage on the downstream side of CV-31735. Both CV-31736 and CV-31735 had a valve overhaul and actuator replaced. The as-left leakage was 12 sccm (CV-31736) and 3 sccm (CV-31735).

Note 2: Valve MV-32210 failed due to disc degradation. The valve was disassembled; the disc was repaired, and retested with an as-left leakage of 2 sccm.

Specific testing frequencies for the Appendix J local leak rate tests are reviewed prior to every refueling outage. An outage scope document is issued to document local leak rate test periodicity and to ensure pre-maintenance and post-maintenance testing is complete. The post-outage report provides a written record of extended testing interval changes and reasons for the changes based upon testing results, trending and maintenance history.

Based on the above measures, the LLRT program will provide continuing assurance that the most likely sources of leakage will be identified and repaired.

3.3 Containment Inspection

General visual examinations of the accessible surfaces of the primary containment are performed in accordance with the Containment Inservice Inspection Program. These examinations are performed to assess the general condition of the containment vessel and to satisfy the visual examination requirements of ASME Code Section XI, Subsection IWE. These examinations are performed in sufficient detail to identify areas of metal containment vessel deterioration and distress.

Detailed visual examinations are performed to determine the magnitude and extent of deterioration of suspect surfaces initially detected by general visual examinations of the containment vessel. The conditions reported during the examinations are evaluated to determine acceptability. The conditions are acceptable if it is determined that there is no evidence of damage or degradation sufficient to warrant further evaluation or performance of repair and replacement activities. These examinations are performed once each inspection period (three or four years).

The metal containment is visually examined under two separate programs. The first is the Containment Inservice Inspection Program discussed in Section 3.3.1. This program includes provisions to satisfy the visual examination requirements of ASME Code Section XI, Subsection IWE and 10 CFR 50, Appendix J, Option B. A visual examination is made of the accessible interior and exterior surfaces of containment in order to identify evidence of deterioration that may affect the containment structural integrity or leak tightness. If signs of corrosion are evident that exceed the acceptance standard (IWE-3500), they must be either corrected by a repair or replacement activity or deemed acceptable for continued service by an engineering evaluation. Both RG 1.163, September 1995, and the ASME Code require a general visual examination of the accessible liner surfaces three times in a ten year period.

ASME Code Section XI, Subsection IWL does not apply to the PINGP.

The second program is the Containment Coatings Inspection and Assessment Program discussed in Section 3.3.4. This program mandates a visual inspection and assessment of the protective coatings on the containment structure and equipment in the readily accessible areas of the reactor containment building every refueling outage. This program is implemented to ensure that the integrity of the coatings is maintained in accordance with the NSPM response to NRC Generic Letter 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized Water Reactors,” for the PINGP.

The inspection frequency of the above programs ensures that when an area of concern is identified, it only affects a small localized area. Corrective action is taken following significant signs of paint blistering, peeling, or corrosion.

3.3.1 <u>Containment Inservice Inspection Program</u>

NSPM has established a containment Inservice Inspection Program for the PINGP in accordance with 10 CFR 50.55a for Class MC components. The third IWE inspection interval has been developed in accordance with the requirements of the 2013 Edition of the ASME Code, Section XI, Subsection IWE, as modified by 10 CFR 50.55a. The scope of the program includes the accessible pressure retaining containment surface areas including: Containment vessel surfaces and integral attachments, surfaces requiring augmented examination, mechanical/ electrical penetrations, moisture barriers, pressure retaining bolting and Appendix J tested IWE components. The first 10-year inspection interval from September 9, 1996, through September 9, 2009, was conducted in accordance with the ASME IWE 1992 Edition with the 1992 Addenda. The second 10-year inspection interval, from September 10, 2008, through September 9, 2018, applied Subsection IWE, 2001 Edition with the 2003 Addenda. The third 10-year inspection interval, from September 10, 2018, to September 9, 2028, applies Subsection IWE, 2013 Edition.

Each 10-year inspection interval consists of three examination periods. A visual examination of the interior and exterior containment vessel surface areas is required each period by ASME Section XI and is implemented by the PINGP IWE Containment Inspection Program. The Inspection Periods are divided into refueling outages as shown in the following table.

Table 18 – PINGP Units 1 and 2 IWE Containment Inspection Intervals

First Interval			**Unit 1**		**Unit 2**	
Inspection Period	**Start Date**	**End Date**	**Outage**	**Start Date (Approx.)**	**Outage**	**Start Date (Approx.)**
1	9/9/1996	9/9/2001	1R19 1R20 1R21	Oct. 1997 April 1999 Jan. 2001	2R18 2R19 2R20	April 1997 Oct. 1998 April 2000
2	9/10/2001	9/9/2005	1R22 1R23	Nov. 2002 Sept. 2004	2R21 2R22 2R23	Jan. 2002 Sept. 2003 May 2005
3	9/9/2003	9/9/2009*	1R24 1R25	May 2006 April 2008	2R24 2R25	Dec. 2006 Sept. 2008

* The first interval was extended as allowed by IWA-2430(d).

Second Interval			**Unit 1**		**Unit 2**	
Inspection Period	**Start Date**	**End Date**	**Outage**	**Start Date (Approx.)**	**Outage**	**Start Date (Approx.)**
1	9/10/2008	9/9/2011	1R26 1R27	Sept. 2009 April 2011	2R26	April 2010
2	9/10/2011	9/9/2015	1R28 1R29	Oct. 2012 Sept. 2014	2R27 2R28 2R29	Feb. 2012 Sept. 2013 Sept. 2015
3	9/10/2015	9/9/2018	1R30	Oct. 2016	2R30	Nov. 2016

Third Interval			**Unit 1**		**Unit 2**	
Inspection Period	**Start Date**	**End Date**	**Outage**	**Start Date (Approx.)**	**Outage**	**Start Date (Approx.)**
1	9/10/2018	9/9/2021	1R31 1R32	Sept. 2018 Sept. 2020	2R31	Oct. 2019
2	9/9/2021	9/9/2025	1R33 1R34	Sept. 2022 Sept. 2024	2R32 2R33	Oct. 2021 Oct. 2023
3	9/10/2025	9/9/2028	1R35* 1R36*	TBD-2026 TBD-2028	2R34* 2R35*	TBD-2025 TBD-2027

* Specific dates for these refueling outages have not been established yet.

The Containment Inservice Inspection Program is not affected by the proposed amendment for Appendix J testing.

Approved Alternatives to Subsection IWE Requirements

For the First IWE Inservice Inspection Interval the following NRC approved alternatives or relief requests were implemented.

Relief Request No.	10 CFR 50.55a – ASME Code IWE Section	Issue Identification	Recommended NRC Action	Remarks
MC-1	IWA-2300	Qualification of NDE Personnel	(a)(3)(ii)	authorized
MC-2	Table IWE-2500-1, Category E-D, Items E5.10 and E.5-20	VT-3 Examination of Seals and Gaskets	(a)(3)(ii)	authorized
MC-3	Table IWE-2500-1, Category E-G, Item E8.20	Torque/Tension Test of Pressure Retaining Bolting	(a)(3)(ii)	authorized
MC-4	IWE-2200(g)	Preservice Examination of New Paint or Coating	(a)(3)(i)	authorized
MC-5	IWE-2500(b)	Visual examination of paint and coatings prior to removal	(a)(3)(ii)	authorized
MC-6	IWE-2420(b) and IWE-2420(c)	Successive Examination after repairs	(a)(3)(ii)	authorized
MC-7	Table IWE-2500-1, Category E-A, Items E1.12 and E1.20	Visual Examination and Personnel Qualification	(a)(3)(i)	authorized

For the Second and the Third IWE Inservice Inspection Intervals, there were no NRC approved alternatives or relief requests.

Interval and Inspection Periods

The required ASME Section XI, Subsection IWE examinations are scheduled and tracked using a database. The current containment in-service inspection interval for the PINGP Units 1 and 2 are summarized in the table below.

Table 19 – PINGP Units 1 and 2 Current IWE Interval

System Identification	**Examination Description**	**Item Number**	**Examination Method**	**Period Schedules**		
				1	2	3
Examination Category E-A, Containment Surfaces						
Containment Vessel	Accessible Surface Areas	E1.11	General Visual	X	X	X
	Pressure Retaining Bolting	E1.11	General Visual	X	X	X
	Moisture Barrier	E1.130	General Visual	X	X	X
Examination Category E-C, Containment Surfaces Requiring Augmented Examination						
Containment Vessel	Visible Surfaces	E4.11	VT-1 detailed[1] visual exam			
	Surface Area Grid Minimum Wall Thickness Location	E4.12	UT ultrasonic[1] thickness measurements			
Examination Category E-G, Pressure Retaining Bolting						
Containment Vessel	Bolted Connections	E8.10	VT-1 detailed[2] visual exam		X	

Note 1: There are no containment surfaces requiring augmented examination. Hence, no examinations are required for the first, second, an third periods.

Note 2: Examination may be performed with the connection assembled and bolting in place under tension, provided the connection is not disassembled during the interval. If the bolted connection is disassembled for any reason during the interval, the examination shall be performed with the connection disassembled.

Item Number Refers to the item numbers listed in ASME Code Section XI, 2013 Edition Table IWE-2500-1.

Period Schedule: The scheduled dates of refueling outages for inspections during the current Containment Inservice Inspection Interval are based on the requirements of ASME Code Section XI, Table IWE-2500-1.

IWE Examination Category E-C, Item Nos. E4.11 and E4.12 – Containment Surfaces Requiring Augmented Examination

This category includes IWE component areas that were selected for augmented examination because of known existing degraded conditions. Surface areas likely to experience accelerated degradation and aging require augmented examination. In addition, interior containment surfaces that are subject to excessive wear causing a loss of protective coatings, deformation or material loss are also examined. Examination methods are detailed visual examinations (VT-1) and ultrasonic testing (UT). The PINGP Units 1 and 2 do not currently have any areas requiring augmented examination identified.

Containment IWE Inspections

- *Recent Containment Vessel Examinations:*

  Unit 1 – Visual Examination of the Containment Vessel was performed during the 2016 Unit 1 fall outage. The containment vessel showed indications of gouges in three locations. The indications were determined accepted by evaluation since they did not reduce the nominal wall thickness of 1.5 inch by more than 10 percent. The indications are thought to be from original construction as the paint is intact with no evidence of repainting and there is no feasible damage mechanism.

  Unit 2 – Visual Examination of the Containment Vessel was performed during the 2017 fall outage. The containment vessel showed no indications.

- *Moisture Barrier Examinations:*

  Unit 1 – The containment moisture barriers were examined during the 2016 fall outage. There were three indications of lack of adhesion and one indication of tearing which were repaired and accepted by preservice examination.

  Unit 2 - The containment moisture barriers were examined during the 2017 fall outage. There were no indications.

3.3.2 Containment Visual Inspection Program

General visual examinations are performed of the accessible interior and exterior surfaces of the containment vessel in order to identify evidence of deterioration that may affect the containment vessel integrity or leak tightness in accordance with the following:

- Surveillance Requirement 3.6.1.1 requires, in part, visual examinations in accordance with the Containment Leak Rate Testing Program.

- TS 5.5.14 currently requires, in part, visual examinations in accordance with the guidelines contained in RG 1.163, “Performance-Based Containment Leak-Test Program,” dated September 1995. Regulatory Position 3 of the regulatory guide requires that these examinations should be conducted prior to initiating a Type A test and during two other refueling outages before the next Type A test if the interval for the Type A test has been extended to ten years, in order to allow for early uncovering of evidence of structural deterioration.

The PINGP Containment Leak Rate Testing Program requires that these examinations be conducted prior to initiating a Type A test and during two other refueling outages before performance of the next Type A test.

With the implementation of the proposed change, TS 5.5.14 will be revised by replacing the reference to RG 1.163 with reference to NEI 94-01, Revision 3-A. A general visual examination of accessible interior and exterior surfaces of the containment for structural deterioration that may affect the containment leak-tight integrity is required by NEI 94-01, Revision 3-A 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.

The PINGP Containment Leak Rate Testing Program credits the detailed method and schedule for inspecting the accessible interior and exterior surfaces of the containment vessel for structural deterioration in accordance with the ASME Section XI, Subsection IWE Containment Inspection Programs for these visual examinations. The tests are performed to meet the requirements of TS 5.5.14 with the incorporation of NEI 94-01, Revision 3-A guidelines.

3.3.3 Inaccessible Areas

For Class MC applications, NSPM shall evaluate the acceptability of the inaccessible areas when conditions exist in the accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

Inaccessible surface areas are identified in the IWE component database and are exempt from examination because they have met the requirements of the original Construction Code. For PINGP Units 1 and 2 the areas that have been identified as inaccessible are those that are embedded in concrete and behind the moisture barrier at the steel concrete interface. Areas embedded in concrete are located below the 706 foot six inch elevation of the containments and are those around the fuel transfer canals.

For each inaccessible area identified, NSPM provides the following information in the Inservice Inspection (ISI) Summary Report, 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 the corrective action.

NSPM has not needed to implement new technologies to perform inspections of inaccessible areas at this time. However, NSPM 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 applicability to the PINGP. 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.

3.3.4 <u>Containment Coatings Inspection Program</u>

The PINGP Containment Coatings Program defines the requirements and responsibilities for a program to implement inspections during refueling outages for the purpose of assessing the condition of the protective coatings on structures and equipment in the reactor containment building. These inspections assure compliance with the NSPM response for PINGP Units 1 and 2 to NRC Generic Letter 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized Water Reactors.”

Results of Recent Coatings Inspections

Unit 1 - Inspections of the coatings in the Unit 1 reactor containment building were completed during the fall 2018 refueling outage and assessed by Engineering. The assessment was compared against the acceptance criteria and coating program procedures. The condition of the containment coatings was acceptable and no immediate corrective actions were required to meet design and license basis requirements. The total quantity of degraded qualified and unqualified coatings remains within the bounds required by design basis, with margin remaining below administrative limits.

Unit 2 - Inspections of the coatings in the Unit 2 reactor containment building were completed during the fall 2017 refueling outage and assessed by Engineering. The assessment was compared with the previous containment coating assessment from the prior refueling outage in accordance with license basis requirements and coating program procedures. Overall, no significant findings were identified. The condition of the containment coatings was acceptable and no immediate corrective actions were required to meet design and license basis requirements. Some desired minor repairs

were initiated to improve margin with respect to the amount of degraded qualified coatings in containment. The total quantity of degraded qualified and unqualified coatings remains within the bounds required by design basis, with margin remaining below administrative limits.

3.3.5 Maintenance Rule

The Maintenance Rule, 10 CFR 50.65, requires licensees to monitor the performance or condition of structures, systems, and components against licensee-established goals and requires that structures be maintained under an effective preventive maintenance program. The Maintenance Rule also requires utilities to take appropriate corrective action when the performance or condition of a structure does not conform to established goals. The containment isolation function of limiting the release of radioactive fission products following an accident has been classified as high risk significant and its condition is monitored pursuant to 10 CFR 50.65 in accordance with the PINGP Maintenance Rule program. Operability of the containment isolation equipment is ensured by compliance with TS Sections 3.6 and 5.5. The proposed amendment affects only the ILRT and LLRT test intervals and does not impact the PINGP Maintenance Rule program.

3.4 Operating Experience

The NRC has issued several operating experience (OE) documents concerning containment conditions. NSPM has reviewed this OE to determine their impact on the PINGP Unit 1 and 2 containments.

During the conduct of the various examinations and tests performed in support of the primary containment monitoring programs previously mentioned, issues that do not meet established criteria or that provide indication of degradation are entered into the site's corrective action program, and corrective actions are planned and performed. Also, a summary of the NSPM responses to industry operating experience for PINGP Units 1 and 2 is provided. The following site specific and industry events have been evaluated for their impact on primary containment:

- NRC Information Notice (IN) 1992-20, “Inadequate Local Leak Rate Testing”
- NRC IN 2004-09, “Corrosion of Steel Containment and Containment Liner”
- NRC IN 2010-12, “Containment Liner Corrosion”
- NRC IN 2011-15, “Steel Containment Degradation and Associated License Renewal Aging Management Issues”
- NRC Regulatory Issue Summary 2016-07, “Containment Shell or Liner Moisture Barrier Inspection”

Each of these operating experience documents is discussed in detail in the following subsections, respectively.

- <u>NRC IN 1992-20, “Inadequate Local Leak Rate Testing” (Reference 20)</u>

  The IN identified that LLRTs in some instances could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during Type B 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.

  Another issue involved leaking flanges because licensees failed to consider all possible leakage paths when they established their leak rate test programs. In the example provided both licensees identified the valves involved in the events as containment isolation barriers, but they failed to consider the gasketed flanges as leakage paths. Both licensees tested the isolation valves in the reverse direction which did not challenge the flanges properly. Any containment isolation valve could have this problem, particularly if the valve is tested in the reverse direction or if both valves on a penetration are outside of containment.

  Discussion:

  PINGP has ten containment penetration bellows on each unit. There is an inboard bellows (near containment) and an outboard bellows (near the Shield building) on each penetration. A single test connection is provided for each bellows section. The connection enables one to pressurize the annular space between the two plies. The LLRT is performed by pressurizing this volume and measuring a leakage rate. During the PINGP Unit 1 1994 refueling outage, an inspection of nine bellows was performed. The bellows were soap tested during the ILRT and no leaks were found. During the PINGP Unit 2 1997 refueling outage, the protective sheet metal covers of the nine containment penetration bellows in the annulus were removed. The bellows were soap tested during the ILRT and no leaks were found. The fuel transfer tube bellows is not accessible and was not inspected.

- <u>NRC IN 2004-09, “Corrosion of Steel Containment and Containment Liner” (Reference 21)</u>

  The IN alerted the industry to occurrences of corrosion in freestanding metallic containments and in the liner plates of reinforced and pre-stressed concrete containments. 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. Inspections of

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

Discussion:

Inspections of the moisture barrier both inside containment and in the annulus are performed each refueling outage. Also, the Containment Inspection Program also requires inspection of the moisture barrier. Any damaged or deteriorated moisture barrier is repaired. During these inspections there has never been an identified instance of standing water near the containment vessel either in the annulus or inside containment. No pitting or excessive corrosion has been identified.

There is a small strip of bare metal above the moisture barrier in the annulus where there is missing primer. The primer was most likely removed during initial installation of the moisture barrier. This has been identified in previous inspections performed for the Containment Inspection Program. Only minor surface rust has occurred in this area. This condition is monitored under the Containment Coatings program and evaluated for repair in accordance with repair practices.

- NRC IN 2010-12, "Containment Liner Corrosion" (Reference 22)

  This IN alerted licensees to several events where the steel liner of the containment building was corroded and degraded. In April of 2009, Beaver Valley Unit 1 reported a through-wall indication of approximately 1 inch diameter. The through-wall liner corrosion was determined to be the result of pitting corrosion originating from the concrete side due to a piece of wood left in contact with the liner from original construction. In 2008, Brunswick Unit 1 discovered two bulged areas on the containment sleeve of the personnel airlock. The bulges were the result of corrosion product buildup between the sleeve and the concrete backing. During construction the sleeve had been wrapped with felt to facilitate expansion. The felt, which had been wetted during original construction, caused numerous locations below the specified minimum wall thickness. In October 2009, Salem Unit 2 found heavy corrosion of the containment liner at the moisture barrier within 6 inches of the concrete floor. The area of corrosion had been considered inaccessible as it was covered with insulation. Previous examinations had failed to identify indications of corrosion such as rust stains on the floor. It was determined the corrosion was the result of service water leakage from the containment fan coil units.

Discussion:

This IN refers only to concrete containment structures with a steel liner approximately 1/2 inch thick in direct contact with the concrete. The PINGP containments are a steel vessel 1-1/2 inches thick in which only the bottom head is encased in concrete. None-the-less, the containment vessels could be subject to similar corrosion beneath the moisture barrier or on portions of the bottom head encased in concrete on both the inside and outside diameters.

The potential for corrosion of the containment vessels has been a high priority issue for PINGP since 1998 due to refueling cavity leakage. As a result, numerous actions were undertaken associated with refueling cavity leakage and containment vessel. Several NRC commitments were made under License Renewal. Refueling cavity leakage and the potential for containment degradation has also been addressed in ISI Post-Outage 90 Day Summary Reports.

Because the PINGP containment vessels are largely accessible from both sides, and periodically inspected as part of the IWE Program, there is no significant risk of undetected corrosion in the exposed areas. Recent UT examination of the containment vessels at the floor of the annulus indicates no corrosion in the area of the inside moisture barrier. Corrosion due to a foreign object embedded in the concrete from original construction is possible. However, any areas subject to this type of corrosion are fully encased in concrete on both sides. As a result, there is reasonable assurance of structural integrity and leak tightness.

- NRC IN 2011-15, "Steel Containment Degradation and Associated License Renewal Aging Management Issues" (Reference 23)

  This IN discusses age-related degradation of nuclear power plant steel containments that could impact aging management of the containment structures during the period of extended operation under a renewed operating license. Although this IN describes corrosion due to presence of water in inaccessible areas and degradation of coatings and pitting corrosion of the torus steel shell of Boiling Water Reactor (BWR) Mark I containments, there have also been instances of PWR and other BWR containments due to long term exposure to water and moisture, including that in inaccessible areas. This potential exists for PWR containment structures, especially in areas where water could be trapped against the steel liner (or steel containment vessel) such as between the liner and concrete. The discussion is primarily in the context of actions associated with license renewal and aging management. It concludes "Implementation of the in-service inspection requirements of ASME Code Section XI, Subsection IWE for steel components of steel and concrete containments is necessary in order to ensure the containment will be able to perform its intended functions through the period of extended operation."

Discussion:

Refueling cavity leakage and the potential for containment vessel degradation was a significant license renewal issue. A Root Cause Evaluation was performed and numerous actions such as welded cavity repair and installation of rubber sandplug gaskets to mitigate future leakage. Also, actions were performed to detect potential degradation such as UT thickness readings of the containment vessel and excavation of sumps B and C concrete to allow direct visual inspection. No degradation has been noted. Several commitments, as part of License Renewal, including ongoing actions, were made for inspection and testing to ensure no degradation of either the containment vessel or containment concrete structures.

- NRC IN 2014-07, "Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner" (Reference 24)

The containment basemat metallic shell and liner plate seam welds of PWRs are embedded in 3 to 4-feet thick concrete floor during construction and are typically covered by a leak-chase channel system that incorporates pressurizing test connections. This system allows for pressure testing of the seam welds for leak-tightness during construction and also in service, as required. A typical basemat shell or liner weld leak-chase channel system consists of steel channel sections that are fillet welded continuously over the entire bottom shell or liner seam welds and subdivided into zones, each zone with a test connection. Each test connection consists of a small carbon or stainless steel tube (less than 1-inch diameter) that penetrates through the back of the channel and is seal-welded to the channel steel. The tube extends up through the concrete floor slab to a small steel access (junction) box embedded in the floor slab. The steel tube, which may be encased in a pipe, projects up through the bottom of the access box with a threaded coupling connection welded to the top of the tube, allowing for pressurization of the leak-chase channel. After the initial tests, steel threaded plugs or caps are installed in the test tap to seal the leak-chase volume. Gasketed cover plates or countersunk plugs are attached to the top of the access box flush with the containment floor. In some cases, the leak-chase channels with plugged test connections may extend vertically along the circumference of the cylindrical containment shell or liner to a certain height above the floor.

This IN describes instances where licensees had failed to implement inservice inspection requirements to inspect leak-chase channel system test connections for evidence of moisture intrusion that could reach the containment liner. Examples of the degradation identified include: degradation to metal cover plates, no plans to perform visual examinations of accessible parts of the containment liner plate leak-chase systems, and no requirements in the Subsection IWE containment inservice inspection program to inspect any

portion of these test connections for evidence of moisture intrusion that could reach the containment liner.

Discussion:

As discussed in USAR Subsection 12.2.2.5.2, “Concrete and Steel Interface Design:” The containment vessel plate is sandwiched between internal and external concrete structures and is designed to act as an independent structural steel shell member in its function to resist containment pressure. No leak monitoring channels are provided at the welds, since the welds and plate are designed as an integral structural system exclusive of adjacent concrete structures. No leaks are credible once the leak-tight integrity of the bottom welds has been established. Prior to placing any concrete either inside or outside of the vessel bottom, measures were taken to detect any possible leakage through the bottom plates and welded seams (e.g., butt welded` seams were 100 percent inspected in accordance with ASME Section VIII and a one hour overload pressure test (at 51.8 psig) and a 72 hour leak rate test (at 46 psig) were performed.

- <u>NRC Regulatory Issue Summary 2016-07, “Containment Shell or Liner Moisture Barrier Inspection” (Reference 25)</u>

The NRC staff identified several instances in which containment shell or liner moisture barrier materials were not properly inspected in accordance with ASME Code Section XI, Table IWE-2500-1, Item E1.30. Note 4 (Note 3 in editions before 2013) for Item E1.30 under the “Parts Examined” column states that “Examination shall include moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell or liner at concrete-to-metal interfaces and at metal-to-metal interfaces which are not seal-welded. Containment moisture barrier materials include caulking, flashing, and other sealants used for this application.” Examples of inadequate inspections have included licensees not identifying sealant materials at metal-to-metal interfaces as moisture barriers because they do not specifically match Figure IWE-2500-1, and licensees not inspecting installed moisture barrier materials, as required by Item E1.30, because the material was not included in the original design or was not identified as a “moisture barrier” in design documents.

Discussion:

This OE is directly applicable to PINGP as the inaccessible portions of the containment vessels of both units are sealed with a moisture barrier both on the inside and outside surface of the vessels. These moisture barriers are required to be inspected in accordance with ASME Section XI, IWE as modified by 10 CFR 50.55a.

The containment moisture barrier is specifically addressed in the containment inspection program procedure. Item Number E1.30, for Moisture Barriers examination includes moisture barrier materials intended to prevent intrusion of moisture against inaccessible areas of the pressure retaining metal containment shell at concrete-to-metal interfaces and at metal-to-metal interfaces which are not seal welded. Containment moisture barrier materials include caulking, flashing, and other sealants used for this application. A procedure directs the visual (VT-3) examination of the accessible interior and exterior containment vessel moisture barrier at the concrete-steel interface adjacent to the containment knuckle region at a frequency in accordance with Table IWE-2500-1 (100% each period).

Examination is required once each inspection period and is generally scheduled for the first outage of the period. Moisture barriers with wear, damage, erosion, tear, surface cracks, or other defects that permit intrusion of moisture against inaccessible areas of the pressure retaining surfaces of the containment vessel are addressed with corrective measures. A review of the procedures and work order history show that containment moisture barrier inspections have been performed as required.

3.5 NRC LIMITATIONS AND CONDITIONS

3.5.1 SE for Revision 2 of NEI 94-01 and EPRI Topical Report No. 1009325

In the safety evaluation issued by the NRC dated June 25, 2008, it was concluded that the methodology in NEI 94-01, Revision 2, and in EPRI Topical Report No. 1009325, Revision 2, are acceptable for referencing by licensees proposing to amend their TS to permanently extend the Type A surveillance test interval to 15 years, subject to the conditions noted within the safety evaluation.

Responses to the limitations and conditions listed in Section 4.1 of the NRC SE for the application of Revision 2 of NEI 94-01 are provided in the table below. Responses to the limitations and conditions listed in Section 4.2 of the NRC SE for application of Revision 2 of EPRI Topical Report No. 1009325 are provided in the following table.

Table 20 – Limitations and Conditions for Use of Revision 2-A of NEI 94-01

NEI 94-01, Revision 2-A Limitation or Condition	NSPM Response
1. For calculating the Type A leakage rate, the licensee should use the definition in the NEI TR 94-01, Revision 2-A, in lieu of that in ANSI/ANS-56.8-2002. (Refer to SE Section 3.1.1.1.)	NSPM will utilize the definition in Section 5.0 of NEI 94-01, Revision 3-A. This definition remains unchanged from Revision 2 to 3 of the NEI guidance.
2. 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.)	A projected schedule for containment inspections is provided in Subsection 3.3.1 of this enclosure.
3. The licensee addresses the areas of the containment structure potentially subjected to degradation. (Refer to SE Section 3.1.3.)	General visual observations of the accessible interior and external surfaces of the containment structure will continue to be performed in accordance with ASME Code Section XI, Subsection IWE and NEI 94-01, Revision 3-A, Sections 9.2.1 and 9.2.3.2. Refer to Subsection 3.3.2 of this enclosure.
4. The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE Section 3.1.4.)	NSPM has not performed any major repairs or modifications to the PINGP Units 1 and 2 containment structures. Replacement of the steam generators was through the equipment hatch in each unit. No changes were required to the containment for their installation. No major modifications are planned for that would affect the PINGP Unit 1 and 2 containment structures.
5. 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-A, 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.)	NSPM will follow the requirements of Section 9.1 of NEI 94-01, Revision 3-A. This requirement remains unchanged from Revision 2-A to Revision 3-A of NEI 94-01. In accordance with Section 3.1.1.2 of the NRC SE dated June 25, 2008, NSPM 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. Justification for such an extension request will be in accordance with the staff position in RIS 2008-27.(2)

2. NRC RIS 2008-27, “Staff Position on Extension of the Containment Type A Test Interval Beyond 15 Years Under Option B of Appendix J to 10 CFR Part 50,” dated December 8, 2008.

NEI 94-01, Revision 2-A Limitation or Condition	NSPM Response
6. 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 TR 94-01, Revision 2-A, and EPRI Report No. 1009325, Revision 2, including the use of past containment ILRT data.	Not applicable. The PINGP Units 1 and 2 were not licensed under 10 CFR Part 52.

Table 21 – Limitations and Conditions for Use of Revision 2 of EPRI TR No. 1009325

EPRI TR 1009325, Revision 2 Limitation or Condition	NSPM 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 application.	The technical adequacy of the PRA for PINGP Units 1 and 2 is addressed in Section 3.6 of this enclosure.
2. 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[3] of this SE. 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 percent of the total population dose, whichever is less restrictive. In addition, a small increase in [conditional containment failure probability] CCFP should be defined as a value marginally greater than that accepted in 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 points. While acceptable for this application, the NRC staff is not endorsing these	EPRI Report No. 1009325, Revision 2-A, incorporates these population dose and conditional containment failure probability acceptance guidelines, and these guidelines have been used for the PINGP plant-specific risk assessment. The increase in population dose is discussed in Enclosure 2. The increase in conditional containment failure probability is discussed in Enclosure 2.

3. The SE for this EPRI report indicates that the clarification regarding small increases in risk is provided in Section 3.2.4.5; however, it is actually provided in Section 3.2.4.6.

EPRI TR 1009325, Revision 2 Limitation or Condition	NSPM Response
threshold values for other applications. Consistent with this limitation and condition, EPRI Report No. 1009325 will be revised in the "-A" version of the report, to change the population dose acceptance guidelines and the CCFP guidelines.	
3. The methodology in EPRI Report No. 1009325, Revision 2, is acceptable except for the calculation in the increase in expected population dose (per year of reactor operation). In order to make the methodology acceptable, the average leak rate for the pre-existing containment large 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 NSPM for PINGP Units 1 and 2 is 100 L_a, based on the recommendations in the latest EPRI report and as recommended in the NRC SE. 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.
4. A LAR is required in instances where containment overpressure is relied upon for ECCS performance.	Neither PINGP Unit 1 nor Unit 2 relies on containment overpressure for ECCS performance.

3.5.2 Safety Evaluation for Revision 3-A of NEI 94-01

Responses to the limitations and conditions for application of NEI 94-01, Revision 3-A that are listed in Section 4.0 of the NRC safety evaluation (dated May 8, 2008) are presented in the following table for PINGP Units 1 and 2.

Table 22 – Limitations and Conditions for Use of Revision 3 of NEI 94-01

NEI 94-01, Revision 3-A Limitation or Condition	NSPM Response
1. NEI TR 94-01, Revision 3-A, 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 to be increased to 75 months with the requirement that a licensee's post-outage report include the margin between Type B and Type C leakage rate summation and its regulatory limit.	The post-outage report shall include the margin between the Type B and Type C minimum pathway leak rate summation value, as adjusted to include the estimate of applicable Type C leakage understatement, and its regulatory limit of 0.60 L_a.

NEI 94-01, Revision 3-A Limitation or Condition	NSPM Response
In addition, a corrective action plan shall be developed to restore the margin to an acceptable level.	When the potential leakage understatement adjusted Type B and Type C minimum pathway leak rate total is greater than the PINGP administrative leakage summation limit of 0.50 L_a, but less than the TS limit of 0.60 L_a, then an analysis and a corrective action plan will be prepared to restore the leakage summation margin to less than the PINGP administrative 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 the manner of timely corrective action (as deemed appropriate) that best focuses on the prevention of future component leakage performance issues.
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 94-01, Revision 3-A. 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. This is Topical Report Condition 1.	NSPM will apply the 9 month grace period only to eligible Type C components and only for non-routine emergent conditions for the PINGP. Such occurrences will be documented in the record of the tests.
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 LLRT's being performed during plant outages. For the purposes of assessing and monitoring or overall containment leakage potential, the as-found minimum pathway leakage rates for the just	The change 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, represents an increase of 25 percent in the local leak rate test periodicity. As such, NSPM 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 greater than 60 month (up to 75 month) extended test interval. This will result in a combined conservative Type C total for all 60-75 month local leak rate tests being carried forward and included whenever the total leakage summation is required to be updated (either while operating on-line or

NEI 94-01, Revision 3-A Limitation or Condition	NSPM Response
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 94-01, Revision 3-A, Section 12.1.	following an outage). When the potential leakage understatement adjusted leak rate total for those Type C components being tested on a greater than 60 month (up to 75 month) extended interval is summed with the non-adjusted total of those Type C components being tested at less than the 60-75 month interval and the total of the Type B tested components, if the minimum pathway leak rate is greater than the PINGP administrative leakage summation limit of 0.50 L_a, but less than the regulatory limit of 0.60 L_a, then an analysis and corrective action plan shall be prepared to restore the leakage summation value to less than the administrative leakage limit. The corrective action plan shall focus on those components that have contributed the most to the increase in the leakage summation value and the manner of timely corrective action (as deemed appropriate) that best focuses on the prevention of future component leakage performance issues.
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. This is Topical Report Condition 2.	If the potential leakage understatement adjusted minimum pathway leak rate is less than the administrative leakage summation limit of 0.50 L_a, then the acceptability of the 75-month local leak rate test extension for all affected Type C components has been adequately demonstrate and the calculated local leak rate total represents the actual leakage potential of the penetrations.

In addition to Condition 1, which addresses the minimum pathway leak rate Type B and Type C summation margin, NEI 94-01, Revision 3-A, also has the following margin related requirement 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.

In the event an adverse trend in the potential leakage understatement adjusted Type B and Type C summation is identified, an analysis and a corrective action plan are developed to restore the margin to an acceptable level thereby eliminating the adverse trend. The corrective action plan shall focus on those components that have contributed the most to the adverse trend in the leakage summation value.

3.6 PLANT SPECIFIC CONFIRMATORY ANALYSIS

3.6.1 Methodology

An evaluation has been performed to assess the risk impact of extending the PINGP Type A test interval from the current 10 years to 15 years. A simplified bounding analysis consistent with the EPRI approach was used for evaluating the change in risk associated with increasing the test interval to 15 years. The approach is consistent with that presented in:

- Appendix H of Electric Power Research Institute, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals: Revision 2 of 1009325,"
- Electric Power Research Institute, "Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals," EPRI Topical Report TR-104285, dated August 1994;
- U.S. NRC, "Performance-Based Containment Leak-Test Program," NUREG-1493, dated September 1995; and,
- Calvert Cliff's liner corrosion analysis described in a letter to the NRC dated March 27, 2002.

The analysis uses results from NSPMs analysis of core damage scenarios (Level 1) and subsequent containment responses (Level 2), for the PINGP Units 1 and 2 that results in various fission product release categories (including intact containment or negligible release).

3.6.2 Probabilistic Risk Assessment (PRA) Acceptability

A) PRA Quality Statement for Permanent 15-Year ILRT Extension

Revision 5.3 of the PINGP PRA model is the most recent evaluation of internal event risk. The PINGP PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the PINGP PRA is based on the single top fault tree methodology, which is a well-known PRA methodology in the industry.

The PRA models have been assessed against RG 1.200. In November 2010, the internal events PRA model was subject to a full-scope peer review conducted in accordance with RG 1.200. The internal flooding portion of the PRA model was not available for peer review at that time. In September 2012, a focused scope peer review was performed on the internal flooding portions of the internal events PRA model against RG 1.200. In May 2014, an additional focused scope peer review of the internal events PRA model was conducted to evaluate model changes made to address incorporation of the Flowserve N9000 Reactor Coolant Pump seals against RG 1.200.

In May 2012, the Fire PRA model was subject to a full-scope peer review conducted in accordance with RG 1.200. Additionally, two focused scope peer reviews against RG 1.200 have been conducted to review changes to the Fire PRA model. The first focused scope peer review was conducted in November 2013 and reviewed the upgrade to the correlations used in determining hot gas layer temperatures. The second focused scope peer review was conducted in December 2017 and reviewed the apportioning of the main control board fire frequency and the implementation of NUREG/CR-6850 (Reference 26) thermal response time to cable damage.

In October 2017, finding closure reviews were conducted on the Internal Events, including Internal Flooding, and Fire PRA models. Dispositioned findings were reviewed and closed using the process documented in Appendix X to NEI 05-04, NEI 07-12 and NEI 12-13, “Close-Out of Facts and Observations,” as accepted by the NRC in RG 1.174. Following this initial review, there were eight outstanding Findings. A focused scope peer review, discussed above, reviewed and closed one outstanding Finding (FSS-B2-01). An additional closure review was performed from April 30 to May 1, 2019. Following completion of this closure review session, five of the examined Findings were determined to be closed. This closure review did not address Finding SY-A17-01, which remains open.

The October 2017 finding closure review contains the finding information for SY-A17-01, which is discussed in detail in Section A.2 of Enclosure 2. The Finding and Observation (F&O) Closure Review process and closure team makeup for the initial closure review was previously described in an NSPM response to an RAI to a LAR for the adoption of a Surveillance Frequency Control Program in accordance with Technical Specification Task Force (TSTF) traveler TSTF-425. The process for the second closure review was equivalent to the first but with a smaller team due to the lower number of findings.

NSPM employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating NSPM nuclear generation sites. 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 the NSPM approach to PRA model maintenance, as it applies to the PINGP PRA.

B) PRA Maintenance and Update

The NSPM risk management process ensures that the applicable PRA models used in this application continue to reflect the as-built and as-operated plant. The process delineates the responsibilities and guidelines for updating the PRA models, and includes criteria for both regularly scheduled and interim PRA model updates. The process includes provisions for monitoring potential areas affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, and industry operational experience), for assessing the risk impact of unincorporated changes, and for controlling the model and associated computer files. The process assesses the impact of these changes on the plant PRA model in a timely manner (typically considered to be once every two refueling outages).

3.6.3 Conclusions of the Plant-Specific Risk Assessment Results

The findings of the PINGP Units 1 and 2 probabilistic risk assessment contained in Enclosure 2 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 fifteen years is very small. Based on the results from the sensitivity calculations presented in Enclosure 2, the following conclusions regarding the assessment of the plant risk are associated with extending the Type A ILRT test frequency to 15 years:

> RG 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. RG 1.174 defines “small” changes in risk as resulting in increases in the core damage frequency (CDF) of greater than 1.0E-6/year but less than 1.0E-5/year, and increases in the large early release frequency (LERF) of greater than 1.0E-7/year but less than 1.0E-6/yr. 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 1.17E-7/year for Unit 1 and 1.13E-7/year for Unit 2 using

the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. Total Internal Events LERF (baseline and change in LERF due to the ILRT extension) is 3.32E-7 for Unit 1 and 2.99E-7 for Unit 2. Therefore, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG 1.174. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. Considering the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 4.86E-8/year for Unit 1 and 4.72E-8/year for Unit 2, the risk increase is "very small" applying the acceptance guidelines of RG 1.174.

When external event risk is included, 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 7.38E-7/year for Unit 1 and 7.33E-7/year for Unit 2 using the EPRI guidance, and total LERF is 1.95E-6/year for Unit 1 and 1.87E-6/year for Unit 2. As such, the estimated change in LERF is determined to be "small" using the acceptance guidelines of RG 1.174. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 3.08E-7/year for Unit 1 and 3.05E-7/year for Unit 2, and the total LERF is 1.52E-6 /year for Unit 1 and 1.45E-6/year for Unit 2. Therefore, the risk increase is "small" using the acceptance guidelines of RG 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 0.028 person-rem/year for Unit 1 and 0.027 person-rem/year for Unit 2. NEI 94-01 states that a "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. These results 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 0.908% for Unit 1 and 0.910% for Unit 2. NEI 94-01 states that increases in the conditional containment failure probability (CCFP) of ≤ 1.5% is "small." Therefore, this increase is judged to be "small."

Therefore, increasing the ILRT interval to 15 years is considered to be "small" since it represents a small change to the PINGP Unit 1 and 2 risk profiles.

3.7 License Renewal Aging Management

The renewed operating licenses for PINGP Unit 1 and 2 were issued on June 27, 2011, after NRC review of the NSPM license renewal application for these units was completed.

The following programs which are part of the supporting basis for this LAR, are also Aging Management Programs for PINGP Units 1 and 2:

- ASME Section XI, Subsection IWE Aging Management In-Service Inspection Program,
- Protective Coating Monitoring and Maintenance Program, and
- 10 CFR 50, Appendix J Program.

3.7.1 ASME Section XI, Subsection IWE Aging Management

The ASME Section XI, Subsection IWE Program (IWE Program) provides for condition monitoring of Class MC pressure-retaining components and their related items, including integral attachments, moisture barriers, and pressure-retaining bolting. It is implemented in accordance with the requirements of 10 CFR 50.55a, with specified limitations, modifications and NRC-approved alternatives, utilizes ASME Section XI, Subsection IWE, 2013 Edition for the current inspection interval, and is updated periodically as required by 10 CFR 50.55a. Repair/Replacement activity requirements associated with this program are in accordance with ASME Section XI, 2007 Edition through the 2008 Addenda.

Class MC components at PINGP Units 1 and 2 include the containment vessels, personnel airlocks, equipment hatches, mechanical penetrations, and electrical penetrations.

The IWE Program monitors for aging effects by performing visual examinations (general, VT-3, VT-1) of the Class MC components and their related items. Visual (VT-1) or volumetric examinations, as applicable, are performed on bolting, and components that require augmented examination. Leak testing is also periodically performed in accordance with the 10 CFR 50, Appendix J Program, to detect leakage from the pressure-retaining Class MC components.

The IWE Program is an existing program which provides for the condition monitoring of Class MC pressure-retaining components and their related items, including integral attachments, moisture barriers, and pressure retaining bolting. The program has been effective in monitoring Class MC components and their related items, and no adverse trends or significant conditions related to these components and items have been identified. Implementation of this program provides reasonable assurance that aging effects are managed such that structures, systems, and components within scope will continue to perform their intended function(s).

3.7.2 Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program monitors performance of Service Level I coated surfaces inside containment through periodic coating examinations, condition assessments, and remedial actions including repair or removal. It provides direction for procurement of Service Level I coatings and prescribes methods to apply and maintain these coatings.

Service Level I protective coatings (i.e., coatings inside containment) are procured, applied, inspected, and maintained in a manner consistent with the NSPM response to GL 98-04, “Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Cooling Accident because of Construction and Protective Coating Deficiencies and Foreign Material in Containment” for PINGP Units 1 and 2. NSPM does not rely upon protective coatings to protect coated carbon steel components at the PINGP Units 1 and 2 from corrosion, and does not credit this program for prevention of corrosion. The programs purpose is to ensure that the amount of coatings that could fail during a LOCA and become debris load on the containment sump B strainers does not exceed the strainers’ design limits.

This is an existing on-going program that has successfully monitored the performance of coatings inside each unit’s containment. Proper maintenance of protective coatings ensures that the quantities of unqualified and degraded qualified coatings inside the containments are maintained below the acceptance limits, and that post-accident safety systems that rely on water recycled through the containment sump system remain operable.

Implementation of this program provides reasonable assurance that the performance of coatings inside the PINGP Unit 1 and 2 containments are monitored effectively. Through periodic visual inspections, the program will continue to detect, evaluate, and correct degraded coatings to assure that the recirculation strainers will not clog from coating debris following a postulated design basis event.

3.7.3 10 CFR 50, Appendix J Program

The 10 CFR Part 50, Appendix J Program provides for containment system examinations and leakage testing. The program includes: scheduling of tests using risk and performance considerations, test methodology, overall containment leakage rate computations, leakage rate summations, acceptance criteria and corrective actions.

Containment leak rate tests are performed to assure that leakage through the primary reactor containment, and systems and components penetrating primary containment, do not exceed allowable leakage rate values as specified in the TSs. 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.

The program conforms to the requirements of 10 CFR 50, Appendix J, Option B. The current program incorporates guidance provided in RG 1.163 as well as NEI 94-01, Revision 0, but will be updated to reflect the guidance of NEI 94-01, Revision 3-A following approval of this LAR. The containments and individual isolation barriers are tested at intervals determined by risk and performance considerations as specified in Option B and associated guidance documents, or as specifically approved by the NRC.

Test results are evaluated against the acceptance criteria given in TS 5.5.14 and the component administrative leakage limits provided in the program documents. Corrective action is taken as necessary.

The 10 CFR Part 50, Appendix J Program is an existing program that has successfully managed the leak-tight integrity of the containment systems since initial plant operation, and has ensured the continuing effectiveness of the containment as a barrier against the release of radioactive material to the environment. This program provides reasonable assurance that aging effects are managed such that SSCs within scope will continue to perform their intended function(s).

4.0 IMPACT ON SUBMITTALS UNDER NRC REVIEW

There is no impact on any submittals currently under NRC review since the proposed TS changes do not involve any specifications that are proposed to be modified in the other submittals.

5.0 REGULATORY ANALYSIS

5.1 Applicable Regulatory Requirements

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 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Appendix J specifies containment leakage testing requirements, including acceptance criteria, test methodology, frequency, and reporting requirements to ensure the leak-tight integrity of the primary containment and the systems and components that penetrate containment.

Adoption of Option B performance-based containment leakage rate testing for Type A, Type B, and Type C testing does not alter the basic method by which testing is performed; but does alter the frequency at which the Type A containment leakage tests and Type B and C LLRTs are required to be performed. Type B and Type C test frequencies are based on evaluation of the leakage history to determine a frequency for testing which provides assurance that leakage limits will not be exceeded. The

proposed change to the ILRT (Type A) frequency does not directly result in an increase in containment leakage. Type B and Type C leakage 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.

10 CFR 50.36, “Technical specifications,” details the content and information that must be included in a station's TS. In accordance with the requirements of 10 CFR 50.36, TS are required to include (1) safety limits and limiting safety system settings; (2) limiting conditions for operation; (3) surveillance requirements; (4) design features; and (5) administrative controls. This proposed change revises TS 5.5.14 which is under the Programs and Manuals subsection of Section 5.0, “Administrative Controls,” to require a program that is in accordance with NEI 94-01, Revision 3.

PINGP Units 1 and 2 were designed and constructed to comply with Northern States Power (NSP – predecessor license holder) understanding of the intent of the AEC General Design Criteria for (GDC) for Nuclear Power Plant Construction Permits, as proposed on July 11, 1967. Since plant construction preceded the issuance of the February 20, 1971, 10 CFR50, Appendix A GDCs, the plant was not reanalyzed and the FSAR revised to reflect these later criteria. However, the AEC safety evaluation report (SER) for the PINGP acknowledged that the AEC had assessed the plant, as described in the FSAR, against the 10 CFR 50, Appendix A GDCs and “… are satisfied that the plant design generally conforms to the intent of these criteria.”

Section 1.2 of the USAR presents a brief description of related plant features provided to meet the design objectives reflected in groups of the proposed GDCs. Section 1.5 of the USAR presents a brief description of related plant features which are provided to meet the design objectives reflected in each of the 70 proposed (July 1967) general design criteria. The succeeding USAR sections state the licensee’s understanding of the intent of the criteria and describe how the plant design complies with those requirements.

Applicable 10 CFR 50, Appendix A, GDC criterion is first presented first followed by similar corresponding AEC GDCs provided for comparison.

A. <u>10 CFR 50 Appendix A, GDC 50 – *Containment design basis*</u>

The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and as required by § 50.44 energy from metal-water and other

chemical reactions that may result from degradation but not total failure of emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

- AEC-GDC Criterion 10 – *Containment*

  Containment shall be provided. The containment structure shall be designed to sustain the initial effects of gross equipment failures, such as a large coolant boundary area, without loss of required integrity and, together with other engineered safety features as may be necessary to retain for as long as the situation requires the functional capability to protect the public.

- AEC-GDC Criterion 49 – *Containment Design Basis*

  The containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so that the containment structure can accommodate without exceeding the design leakage rate the pressures and temperatures resulting from the largest credible energy release following a loss-of-coolant accident, including a considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems.

B. 10 CFR 50 Appendix A, GDC 52 – *Capability for containment leakage rate testing*

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

- AEC-GDC Criterion 54 – *Containment Leakage Rate Testing*

  Containment shall be designed so that an integrated leakage rate testing can be conducted at design pressure after completion and installation of all penetrations and leakage rate measured over a sufficient period of time to verify its conformance with required performance.

- AEC-GDC Criterion 55 – *Containment Periodic Leakage Rate Testing*

  The containment shall be designed so that integrated leakage rate testing can be done periodically at design pressure during plant lifetime.

C. <u>10 CFR 50 Appendix A, GDC 53 – *Provisions for containment testing and inspection*</u>

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leaktightness of penetrations which have resilient seals and expansion bellows.

- <u>AEC-GDC Criterion 56 – Provisions for Testing of Penetrations</u>

  Provisions shall be made for testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at design pressure at any time.

D. <u>10 CFR 50 Appendix A, GDC 54 – *Piping systems penetrating containment*</u>

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

- <u>AEC-GDC Criterion 57 – Provisions for Testing of Isolation Valves</u>

  Capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

The 10 CFR 50, Appendix A GDCs and the AEC proposed GDCs, while worded somewhat differently, are equivalent in that the containment is required to be designed to: 1) sustain the effects of gross equipment failures, e.g., a LOCA, without loss of required integrity and 2) provide for periodic testing of isolation valves and resilient seals/expansion bellows in penetrations to ensure any leakage is within acceptable limits to protect the health and safety of the public.

5.2 Precedent

This LAR is similar in scope to the license amendments listed below to extend the Type A test frequency to 15 years and the Type C test frequency to up to 75 months based on acceptable valve performance previously authorized by the NRC in the associated safety evaluations:

- Sequoyah Nuclear Plant, Units 1 and 2 (Reference 27)
- Catawba Nuclear Station, Units 1 and 2 (Reference 28)
- Millstone Power Station, Unit 2 (Reference 29)
- Vogtle Electric Generating Plant, Units 1 and 2 (Reference 30)
- Point Beach Nuclear Plant, Units 1 and 2 (Reference 31)

5.3 No Significant Hazards Consideration Analysis

Pursuant to 10 CFR 50.90, “Application for amendment of license, construction permit, or early site permit,” Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (hereafter “NSPM”), requests an amendment to revise the Technical Specifications (TSs) for the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2. Specifically, the proposed change revises TS 5.5.14, “Containment Leakage Rate Testing Program,” to require a program that is in accordance with Nuclear Energy Institute (NEI) Topical Report NEI 94-01, Revision 3-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” dated July 2012. This change will allow a permanent extension of the containment integrated leakage rate test (ILRT) (Type A) test interval from 10 years to 15 years. This change will also allow an extension of the containment isolation valve leakage rate (Type C) test frequency from 60 months to up to 75 months for selected components, based on an acceptable performance history.

NSPM has evaluated the proposed change against the criteria of 10 CFR 50.92, “Issuance of amendment,” to determine if the proposed change results in any significant hazards. The following is the evaluation of each of the 10 CFR 50.92(c) criteria:

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

   Response: No

   The proposed change adopts the NRC-accepted guidelines of NEI 94-01 for the development of the NSPM performance-based containment testing program for PINGP Units 1 and 2. NEI 94-01 allows, based on risk and performance, an extension of the Type A and Type C containment leak test intervals. Implementation of these guidelines continues to provide adequate assurance that during design basis accidents, the primary containment and its components will limit leakage rates to less than the values assumed in the plant safety analyses.

The findings of the PINGP risk assessment confirm the general findings of previous studies that the risk impact with extending the containment leak rate is small. In accordance with the guidance provided in Regulatory Guide 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” an extension of the leak test interval in accordance with NEI 94-01, Revision 3-A results in an estimated change within the very small change region.

Since the change is implementing a performance-based containment testing program, the proposed amendment 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 requirement for containment leakage rate acceptance will not be changed by this amendment. Therefore, the containment will continue to perform its design function as a barrier to fission product releases.

Therefore, the proposed change does not involve 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 change to implement a performance-based containment testing program, associated with integrated leakage rate test frequency, does not change the design or operation of structures, systems, or components of the plant. The proposed change would continue to ensure containment integrity and would ensure operation within the bounds of existing accident analyses. There are no accident initiators created or affected by this change.

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

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

   Response: No

   Margin of safety is related to confidence in the ability of the fission product barriers (fuel cladding, reactor coolant system, and primary containment) to perform their design functions during and following postulated accidents. The proposed change to implement a performance-based containment testing program, associated with integrated leakage rate test and local leak rate testing frequency, does not affect plant operations, design functions, or any analysis that verifies the capability of a structure, system, or component of the plant to perform a design function. In addition, this change

does not affect safety limits, limiting safety system setpoints, or limiting conditions for operation.

The specific requirements and conditions of the TS Containment Leakage 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 the TSs is maintained. This 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 implementation of a performance-based containment testing program.

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

Based on the above, NSPM concludes that the proposed amendment does not involve a significant hazards consideration as defined in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.4 Conclusions

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.

6.0 ENVIRONMENTAL EVALUATION

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, "Standards for Protection Against Radiation," 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 effluents 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, "Criteria for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review," specifically paragraph (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.

7.0 REFERENCES

1. Nuclear Energy Institute (NEI) Topical Report NEI 94-01, Revision 3-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” dated July 2012

2. 10 CFR 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors”

3. American National Standards Institute (ANSI) / American Nuclear Society (ANS) 56.8 2002, “Containment System Leakage Testing Requirements”

4. U.S. Nuclear Regulatory Commission (NRC), Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program,” dated September 1995

5. NEI Topical Report NEI 94-01, Revision 2-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” dated October 2008

6. U.S. NRC Regulatory Guide 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” Revision 3

7. U.S. NRC Regulatory Guide 1.200, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,” Revision 2, dated March 2009

8. NUREG-1493, “Performance-Based Containment Leak-Test Program,” dated September 1995

9. Electric Power Research Institute Topical Report TR-104285, “Risk Impact Assessment of Revised Containment Leak Rate Testing Intervals,” dated August 1994

10. U.S. NRC Regulatory Issue Summary (RIS) 2008-27, “Staff Position on Extension of the Containment Type A Test Interval Beyond 15 Years Under Option B of Appendix J to 10 CFR Part 50,” dated December 8, 2008

11. U.S. NRC, “Prairie Island Nuclear Generating Plant, Unit Nos. 1 and 2 – Issuance of Amendments Re: Appendix J, Option B for Containment Leakage System Tests (TAC Nos. M97129 and M97130),” dated February 19, 1997 (ADAMS Accession No. ML022270159)

12. U.S. NRC to Northern States Power Company issuing Amendments 62 and 56, respectively, revising TS Section 4.4.A.3 and TS 4.4.A.5.c, dated February 23, 1983 (ADAMS Accession No. ML022180360)

13. U.S. NRC, “Exemption from Appendix J, 10 CFR Part 50, Prairie Island Nuclear Generating Plant, Unit Nos. 1 and 2 (TAC Nos. 69172 and 69173),” dated September 27, 1988 (ADAMS Accession No. ML022200419)

14. U.S. NRC, “Prairie Island, Units 1 and 2, License Amendments 117 and 110, Respectively, Revising TS Section 4.4.A.5, Frequency of Containment Integrated Leak Rate Test, to 10 CFR Part 50, Appendix J, as Modified by Approved Exemptions,” dated April 18, 1995 (ADAMS Accession No. ML022260030)

15. U.S. NRC, “Prairie Island Nuclear Generating Plant, Unit Nos. 1 and 2 – Issuance of Amendment Re: Appendix J, Option B for Containment Leakage System Tests (TAC Nos. M97129 and M7130),” dated February 19, 1997 (ADAMS Accession No. ML022270159)

16. U.S. NRC, “Prairie Island Nuclear Generating Plant, Unit 1 – Issuance of Amendment Re: Post-Modification Testing of Pressure Containment Boundary (TAC No. MC0605),” dated August 20, 2004 (ADAMS Accession No. ML 042390304)

17. U.S. NRC, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Issuance of Amendments Re: One-Time Extension of Containment Integrated Leakage Rate Test Interval (TAC Nos. MC9272 and MC9273),” dated October 2, 2006 (ADAMS Accession No. ML062400005)

18. U.S. NRC, “Prairie Island Nuclear Generating Plant, Units 1and 2 – Issuance of Amendments Re: Adoption of Alternative Source Term Methodology (TAC Nos. ME2609 and ME2610),” dated January 22, 2013 (ADAMS Accession No. ML112521289)

19. U.S. NRC, “Prairie Island Nuclear Generating Plant, Unit 2 – Issuance of Amendment Re: Exception to Technical Specification 5.5.14 Testing Requirements Associated with Steam Generator Replacement (TAC No. ME9141),” dated September 11, 2013 (ADAMS Accession No. ML13175A208)

20. NRC Information Notice 1992-20: “Inadequate Local Leak Rate Testing,” dated March 3, 1992 (ADAMS Accession No. ML031200473)

21. NRC Information Notice 2004-09: “Corrosion of Steel Containment and Containment Liner,” dated April 27, 2004 (ADAMS Accession No. ML041170030)

22. NRC Information Notice 2010-12: "Containment Liner Corrosion," dated June 18, 2010 (ADAMS Accession No. ML100640449)

23. NRC IN 2011-15, "Steel Containment Degradation and Associated License Renewal Aging Management Issues," dated August 1, 2011 (ADAMS Accession No. ML111460369)

24. NRC Information Notice 2014-07: "Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner," dated May 5, 2014 (ADAMS Accession No. ML14070A114)

25. NRC Regulatory Issue Summary (RIS) 2016-07, "Containment Shell or Liner Moisture Barrier Inspection," dated May 9, 2016 (ADAMS Accession No. ML16068A436)

26. NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities," (EPRI TR-1011989)

27. U.S. NRC, "Sequoyah Nuclear Plant, Units 1 and 2 – Issuance of Amendments to Revise Technical Specification for Containment Leakage Rate Program (CAC Nos. MF5366 and MF5367)," dated November 30, 2015 (ADAMS Accession No. ML15320A218)

28. U.S. NRC, "Catawba Nuclear Station, Units 1 and 2 – Issuance of Amendments Regarding Extension of the Containment Integrated Leak Rate Test Intervals (CAC Nos. MF7265 and MF7266)," dated September 12, 2016 (ADAMS Accession No. ML16229A113)

29. U.S. NRC, "Millstone Power Station, Unit No. 2 – Issuance of Amendment No. 335 Regarding Revision to the Integrated Leak Rate Type A and Type C Test Intervals (EPID L-2017-LLA-0316)," dated September 25, 2018 (ADAMS Accession No. ML18246A007)

30. U.S. NRC, "Vogtle Electric Generating Plant, Units 1 and 2 – Issuance of Amendments to Extend The Containment Type A Leak Rate Test Frequency to 15 Years and Type C Leak Rate Test Frequency to 75 Months (CAC Nos. MG0240 and MG0241; EPID L-2017-LLA-0295)," dated October 29, 2018 (ADAMS Accession No. ML18263A039)

31. U.S. NRC, "Point Beach Nuclear Plant, Units 1 and 2 – Issuance of Amendments to Extend Containment Leakage Rate Test Frequency (EPID L-2018-LLA-0097)," dated April 25, 2019 (ADAMS Accession No. ML19064A904)

ENCLOSURE 1

ATTACHMENT 1

PRAIRIE ISLAND NUCLEAR GENERATING PLANT

LICENSE AMENDMENT REQUEST

REVISE TECHNICAL SPECIFICATION 5.5.14 TO PERMANENTLY EXTEND CONTAINMENT LEAKAGE RATE TEST FREQUENCY

TECHNICAL SPECIFICATION PAGES (Markup)

2 pages follows

5.5 Programs and Manuals (continued)

5.5.14 Containment Leakage Rate Testing Program

a. A program shall be established to implement 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 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~~"Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995~~, as modified by the following exception~~s~~:

   1. Unit 1 and Unit 2 (steam generator (SG) replacement commencing Fall 2013) are excepted from post-modification integrated leakage rate testing requirements associated with SG replacement.

   ~~2. Exception to NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J", Section 9.2.3, to allow the following:~~

      ~~(i). The first Unit 1 Type A test performed after December 1, 1997 shall be performed by December 1, 2012.~~

      ~~(ii). The first Unit 2 Type A test performed after March 7, 1997 shall be performed by March 7, 2012.~~

b. The peak calculated containment internal pressure for the design basis loss of coolant accident is less than the containment internal design pressure, P_a, of 46 psig.

c. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.15% of primary containment air weight per day. For pipes connected to systems that are in the auxiliary building special ventilation zone, the total leakage shall be less than 0.06% of primary containment air weight per day at pressure P_a. For pipes connected to systems that are exterior to both the shield building and the auxiliary building special ventilation zone, the total leakage past isolation valves

shall be less than 0.006% of primary containment air weight per day at pressure P_a.

ENCLOSURE 1

ATTACHMENT 2

PRAIRIE ISLAND NUCLEAR GENERATING PLANT

LICENSE AMENDMENT REQUEST

REVISE TECHNICAL SPECIFICATION 5.5.14 TO PERMANENTLY EXTEND CONTAINMENT LEAKAGE RATE TEST FREQUENCY

TECHNICAL SPECIFICATION PAGES (Retyped)

1 page follows

5.5 Programs and Manuals (continued)

5.5.14 Containment Leakage Rate Testing Program

a. A program shall be established to implement 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 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:

   1. Unit 1 and Unit 2 (steam generator (SG) replacement commencing Fall 2013) are excepted from post-modification integrated leakage rate testing requirements associated with SG replacement.

b. The peak calculated containment internal pressure for the design basis loss of coolant accident is less than the containment internal design pressure, P_a, of 46 psig.

c. The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.15% of primary containment air weight per day. For pipes connected to systems that are in the auxiliary building special ventilation zone, the total leakage shall be less than 0.06% of primary containment air weight per day at pressure P_a. For pipes connected to systems that are exterior to both the shield building and the auxiliary building special ventilation zone, the total leakage past isolation valves shall be less than 0.006% of primary containment air weight per day at pressure P_a.

ENCLOSURE 2

PRAIRIE ISLAND NUCLEAR GENERATING PLANT

LICENSE AMENDMENT REQUEST

REVISE TECHNICAL SPECIFICATION 5.5.14 TO PERMANENTLY EXTEND CONTAINMENT LEAKAGE RATE TEST FREQUENCY

PRAIRIE ISLAND NUCLEAR GENERATING PLANT EVALUATION OF RISK SIGNIFICANCE OF PERMANENT ILRT EXTENSION

(By Jensen Hughes for Xcel Energy)

46 pages follow

JENSEN HUGHES

Advancing the Science of Safety

Prairie Island Nuclear Generating Plant:
Evaluation of Risk Significance of Permanent ILRT Extension

16058-CALC-01

Prepared for:

Xcel Energy®

Project Number: 1RCA16058
Project Title: Permanent ILRT Extension

Revision: 1

		Name and Date
Preparer: Justin Sattler		Digitally signed by Justin Sattler Date: 2019.10.04 10:51:12-05'00'
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REVISION RECORD SUMMARY

Revision	Revision Summary
0	Initial Issue
1	Minor editorial revision made to Section A.1 based on NSPM comments. Updated References 33 and 34.

TABLE OF CONTENTS

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) from ten years to fifteen years. The extension would allow for substantial cost savings as the ILRT could be deferred for additional scheduled refueling outages for the Prairie Island Nuclear Generating Plant (PINGP). The risk assessment follows the guidelines from NEI 94-01, Revision 3-A [Reference 1], 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 Revision 2 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 10 CFR 50, 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 the 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 assessments 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" [Reference 2].

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), 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 PINGP.

NEI 94-01 Revision 3-A supports using EPRI Report No. 1009325 Revision 2-A (EPRI 1018243), "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 [Reference 2]. 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 requires that visual examinations be conducted during at least three other outages, and in the outage during which the ILRT is being conducted. These requirements are not 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. Since the Type A test does not impact CDF, 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 [Reference 1].

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 [Reference 6] and Safety Evaluations (SEs) 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 [Reference 24]. 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 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 [Reference 1].

3.0 REFERENCES

The following references were used in this calculation:

1. *Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, Revision 3-A, 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, Revision 3, January 2018.
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: Surry Unit 1*, Main Report NUREG/CR-4551, SAND86-1309, Volume 3, Revision 1, Part 1, October 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. Calculation PRA-PI-QU, “PRA Level 1 Quantification,” Revision 5.3, November 2017.
18. Calculation FPRA-PI-FQ, “Fire PRA Quantification Notebook,” Revision 5.3, April 2018.

19. Prairie Island Nuclear Generating Plant, License Renewal Application, Appendix E – Environmental Report, April 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. Letter from U. S. Nuclear Regulatory Commission to S. D. Northard (Northern States Power Company - Minnesota, Prairie Island Nuclear Generating Plant) to U. S. Nuclear Regulatory Commission, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Issuance of Amendments Re: Transition to NFPA-805 “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants” (CAC Nos. ME9734 and ME9735),” Docket Nos. 50-282 and 50-306, ML17163A027, August 8, 2017.
28. Generic Issue 199 (GI-199), “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants: Safety/Risk Assessment,” ML100270582, September 2010.
29. “The Nuclear Energy Institute - Seismic Risk Evaluations for Plants in the Central and Eastern United States,” ML14083A596, March 2014.
30. Work Order Package 00435335 01, Prairie Island Unit 1, “SP 1071.5SP 1071.5 ILRT Final Preparations and Test Proc,” October 23, 2012.
31. Work Order Package 00435335 01, Prairie Island Unit 1, “SP 2071.5 ILRT Final Preparations and Test Proc,” January 26, 2012.
32. V.SPA.18.011, “Prairie Island Re-Examination of External Events Evaluation in the IPEEE,” Revision 0, June 2018.
33. NEI letter to NRC, “Final Revision of Appendix X to NEI 05-04/07-12/12-16, Close-Out of Facts and Observations (F&Os),” dated February 21, 2017 (ADAMS Accession No. ML17086A450).
34. Technical Letter Report ML112070867, Containment Liner Corrosion Operating Experience Summary, Revision 1, August 2011.
35. V.SPA.18.011, “Prairie Island Internal Events Probabilistic Risk Assessment Peer Review Finding Closure,” Revision 1, February 2018.
36. Regulatory Guide 1.200, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,” Revision 2, March 2009.

37. V.SPA.19.007, “Prairie Island Internal Events and Fire Probabilistic Risk Assessment Peer Review Findings Closure,” Revision 0, May 2019.
38. V.SPA.17.009, “PINGP Fire PRA Closure Report,” Revision 0, November 2017.
39. V.SPA.17.010, “Prairie Island Internal Events Probabilistic Risk Assessment Peer Review Findings Closure,” Revision 1, October 2017.
40. Letter L-PI-19-014 from NSPM to the NRC, “Response to Request for Additional Information: Application to Adopt 10 CFR 50.69, “Risk- Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors” (EPID L-2018-LLA-0196),” dated April 29, 2019, ML19119A216.
41. Letter L-PI-18-051 from NSPM to the NRC, “Response to Request for Additional Information: Application for Technical Specification Change Regarding Risk-Informed Justification for the Relocation of Specific Surveillance Frequency Requirements to a Licensee Controlled Program (EPID: L-2018-LLA-0065),” dated September 17, 2018, ML18261A231.
42. V.SPA.18.002, “PINGP FPRA Focused-Scope Peer Review,” Revision 0, January 2018.

4.0 ASSUMPTIONS AND LIMITATIONS

The following assumptions were used in the calculation:

- The acceptability (i.e., technical adequacy) of the PINGP PRA [Reference 17] is consistent with the requirements of Regulatory Guide 1.200, as detailed in Appendix A.
- The PINGP Level 1 and 2 internal events PRA models [Reference 17] provide representative results.
- It is appropriate to use the PINGP internal events PRA model to effectively describe the risk change attributable to the ILRT extension. An analysis is performed in Section 5.2.7 to show the effect of including external event models for the ILRT extension. The Seismic risk from GI-199 [Reference 28] and Fire PRA model Revision 5.3 [Reference 18] are used for this analysis.
- Accident classes describing radionuclide release end states are defined consistent with EPRI methodology [Reference 24].
- The representative containment leakage for Class 1 sequences is $1L_a$. Class 3 accounts for increased leakage due to Type A inspection failures [Reference 24].
- 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 [Reference 24].
- While precise numbers are maintained throughout the calculations, some values have been rounded when presented in this report. Therefore, summing individual values within tables may yield a different result than the sum result shown in the tables.

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 PINGP. 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.

<u>NUREG/CR-3539 [Reference 10]</u>

Oak Ridge National Laboratory (ORNL) 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.

<u>NUREG/CR-4220 [Reference 11]</u>

NUREG/CR-4220 is a study performed by Pacific Northwest Laboratories for the NRC in 1985. The study reviewed over two thousand license event reports (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 0.02 person-rem per year…"

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

NUREG-1150 and the technical basis, NUREG/CR-4551 [Reference 7], 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 Surry. The ex-plant calculation can be delineated to total person-rem for each identified Accident Progression Bin (APB) from NUREG/CR-4551. With the PINGP Level 2 model end-states assigned to one of the NUREG/CR-4551 APBs, it is considered adequate to represent PINGP. (The meteorology and site differences other than population are assumed not to play a significant role in this evaluation.)

<u>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]</u>

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.

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

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.

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

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 PINGP 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 PINGP ILRT Extension Risk Assessment includes the following:

- CDF and LERF Model results [Reference 17, Reference 18]
- Dose within a 50-mile radius [Reference 19]
- ILRT results to demonstrate adequacy of the administrative and hardware issues [References 30 and 31]

PINGP Model

The Internal Events PRA Model that is used for PINGP is characteristic of the as-built plant. The current Level 1 and LERF model is a linked fault tree model [Reference 17]. The CDF is 1.28E-5/year for Unit 1 and 1.25E-5/year for Unit 2; the LERF is 2.15E-7/year for Unit 1 and 1.86E-7/year for Unit 2 [Reference 17]. Table 5-1 and Table 5-2 provide a summary of the Internal Events CDF and LERF results for the PINGP PRA Model.

The total Fire CDF is 6.64E-5/year for Unit 1 and 6.61E-5/year for Unit 2; the total Fire LERF is 9.64E-7/year for Unit 1 and 9.27E-7/year for Unit 2 [Reference 18]. Other external event risk is screened in Reference 32. The seismic risk is taken from GI-199 [Reference 28]. Refer to Section 5.2.7 for further details on external events as they pertain to this analysis.

Table 5-1 – Internal Events CDF

Internal Events	Unit 1 Frequency (per year)	Unit 2 Frequency (per year)
Internal Floods	5.39E-06	4.30E-06
Transients[1]	1.07E-06	1.59E-06
Feedwater/Main Steam Break Inside Containment	1.64E-06	1.63E-06
LOCAs	2.83E-06	2.85E-06
ISLOCA	5.05E-08	5.05E-08
SGTR	1.54E-06	1.65E-06
RPV Rupture	2.60E-08	2.60E-08
Loss of Offsite Power (LOOP)	2.97E-07	3.58E-07
Total Internal Events CDF	**1.28E-05**	**1.25E-05**

1. Note: This “transient” includes the following initiating events from Reference 17: transient, LOAC, LOCC, LOCL, LOCT, LODC, LOIA.

Table 5-2 – Internal Events LERF

Internal Events	Unit 1 Frequency (per year)	Unit 2 Frequency (per year)
Internal Floods	5.64E-08	4.50E-08
Transients[1]	8.46E-09	1.32E-08
Feedwater/Main Steam Break Inside Containment	1.66E-08	1.65E-08
LOCAs	3.26E-08	3.28E-08
ISLOCA	5.05E-08	5.05E-08
SGTR	4.80E-08	2.48E-08
RPV Rupture	2.30E-10	2.30E-10
LOOP	2.18E-09	2.59E-09
Total Internal Events LERF	**2.15E-07**	**1.86E-07**

1. Note: This “transient” includes the following initiating events from Reference 17: transient, LOAC, LOCC, LOCL, LOCT, LODC, LOIA.

Population Dose Calculations

The population dose calculation was reported in the Severe Accident Mitigation Alternatives (SAMA) analysis [Reference 19]. Table 5-3 presents dose exposures calculated from methodology described in Reference 1 and data from Reference 19. Reference 19 H-XX-X (Intact) Release Category corresponds to EPRI Accident Class 1. L-CI-E (Containment Isolation failure) Release Category corresponds to EPRI Accident Class 2. Since they are not associated with other classes, five containment end-states correspond to EPRI Accident Class 7 (H-H2-E, L-H2-E, H-OT-L, L-CC-L, H-DH-L, and L-DH-L Release Categories); the EPRI Accident Class 7 dose is calculated via a weighted average using the frequencies provided in Reference 19. The SGTR Release Category and ISLOCA Release Category correspond to EPRI Accident Class 8; dose used in this analysis is weighted via the ISLOCA and SGTR frequencies in this calculation. Class 3a and 3b population dose values are calculated from the Class 1 population dose and represented as $10L_a$ and $100L_a$, respectively, as guidance in Reference 1 dictates.

Table 5-3 – Population Dose

EPRI Category	Unit 1 Dose (person-rem)	Unit 2 Dose (person-rem)
Class 1	1.75E+03	1.75E+03
Class 2	3.40E+06	3.40E+06
Class 7	3.87E+05	4.31E+05
Class 8 (SGTR)	5.62E+06	5.62E+06
Class 8 (ISLOCA)	2.26E+07	2.26E+07

Release Category Definitions

Table 5-4 defines the accident classes used in the ILRT extension evaluation, which is consistent with the EPRI methodology [Reference 24]. 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 5-4 – EPRI Containment Failure Classification [Reference 24]

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 5-4, 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 2 / 217 = 0.0092). For Class 3b, the probability is based on the Jeffreys non-informative prior for no "large" failures in 217 tests (i.e., 0.5 / (217+1) = 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 delta LERF 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 PINGP, as detailed in Section 5.2, involves subtracting LERF risk from the CDF that is applied to Class 3b because this portion of LERF is unaffected by containment integrity. To be consistent, the same change is made to the Class 3a CDF, even though these events are not considered LERF.

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 1009325 [Reference 24] 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 5-5.

The analysis performed examined PINGP-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 1009325, Class 1 sequences [Reference 24]).
- 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 1009325, Class 3 sequences [Reference 24]).
- Accident sequences involving containment bypassed (EPRI 1009325, Class 8 sequences [Reference 24]), large containment isolation failures (EPRI 1009325, Class 2 sequences [Reference 24]), and small containment isolation “failure-to-seal” events (EPRI 1009325, Class 4 and 5 sequences [Reference 24]) 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 5-5 – 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)
7	Failures Induced by Phenomena (Early and Late)
8	Bypass (SGTR and 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 5-5.

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 1009325 [Reference 24]). 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 5-5 were developed for PINGP by first determining the frequencies for Classes 1, 2, 6, 7, and 8.

Table 5-6 presents the grouping of each release category in EPRI Classes based on the associated description. 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 NEI Interim Guidance [Reference 3] and the definitions of accident classes 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.

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. The PINGP PRA model already includes a pre-existing leak basic event, so its contribution to total LERF was not subtracted from the CDF used to find the Class 3 risk. Therefore, the portion of LERF removed is the total LERF less the contribution from the pre-existing leak: 2.15E-7 – 8.61E-8 = 1.29E-7 for Unit 1 and 1.86E-7 – 8.19E-8 = 1.04E-7 for Unit 2. The frequency of a Class 3a failure is calculated by the following equation:

$$Freq_{U1class3a} = P_{class3a} * (CDF - LERF') = \frac{2}{217} * (1.28\text{E-}5 - 1.29\text{E-}7) = 1.17\text{E-}7$$

$$Freq_{U2class3a} = P_{class3a} * (CDF - LERF') = \frac{2}{217} * (1.25\text{E-}5 - 1.04\text{E-}7) = 1.14\text{E-}7$$

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:

$$Freq_{U1class3b} = P_{class3b} * (CDF - LERF') = \frac{.5}{218} * (1.28\text{E-}5 - 1.29\text{E-}7) = 2.91\text{E-}8$$

$$Freq_{U2class3b} = P_{class3b} * (CDF - LERF') = \frac{.5}{218} * (1.25\text{E-}5 - 1.04\text{E-}7) = 2.83\text{E-}8$$

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 SAMA [Reference 19] provides the most recent plant-specific risk profile; since the model revision 5.3 [Reference 17] does not calculate Intact frequency, the SAMA Intact frequency is scaled using the revision 5.3 CDF, calculated below:

$$Freq_{U1Intact} = Intact_{U1SAMA}/CDF_{U1SAMA} * CDF_{U1Rev5.3}) = 7.28\text{E-}6 / 9.85\text{E-}6 * 1.28\text{E-}5 = 9.49\text{E-}6$$

$Freq_{U2Intact} = Intact_{U2SAMA}/CDF_{U2SAMA} * CDF_{U2Rev5.3}) = 8.52\text{E-}6 / 1.21\text{E-}5 * 1.25\text{E-}5 = 8.77\text{E-}6$

The Intact frequency for internal events is 9.49E-6 for Unit 1 and 8.77E-6 for Unit 2. The EPRI Accident Class 1 frequency is then adjusted by subtracting the EPRI Class 3a and 3b frequency (to preserve total CDF), calculated below:

$Freq_{U1class1} = Freq_{U1Intact} - (Freq_{U1class3a} - Freq_{U1class3b})$

$Freq_{U2class1} = Freq_{U2Intact} - (Freq_{U2class3a} - Freq_{U2class3b})$

Class 2 Sequences. This group consists of accident progression bins with large containment isolation failures. The large isolation failure is in internal events cutsets that contribute 0.0574 of LERF for Unit 1 and 0.0650 of LERF for Unit 2. Multiplying by the respective units' LERF, the EPRI Accident Class 2 frequency is 1.23E-8 for Unit 1 and 1.21E-8 for Unit 2, as shown 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). This frequency is calculated by subtracting the Class 1, 2, and 8 frequencies from the total CDF. For this analysis, the frequency is determined from the EPRI Accident Class 7 frequency listed in Table 5-6.

Class 8 Sequences. This group consists of all core damage accident progression bins in which containment is bypassed via SGTR or ISLOCA. The SGTR initiator is in internal events cutsets that contribute 0.0120 of CDF for Unit 1 and 0.0132 of CDF for Unit 2. The ISLOCA initiators are in internal events cutsets that contribute 0.235 of LERF for Unit 1 and 0.272 of LERF for Unit 2. Thus, the total EPRI Accident Class 8 frequency is the summation of the SGTR and ISLOCA frequencies, 1.59E-6 for Unit 1 and 1.70E-6 for Unit 2, as shown in Table 5-6 and Table 5-7.

Table 5-6 – Accident Class Frequencies (Core Damage)

EPRI Category	Unit 1 Frequency (/yr)	Unit 2 Frequency (/yr)
Class 1	9.49E-06	8.77E-06
Class 2	1.23E-08	1.21E-08
Class 7	1.75E-06	1.97E-06
Class 8 (SGTR)	1.54E-06	1.65E-06
Class 8 (ISLOCA)	5.05E-08	5.05E-08
Total (CDF)	1.28E-05	1.25E-05

Table 5-7 – Baseline Risk Profile

Class	Description	Unit 1 Frequency (/yr)	Unit 2 Frequency (/yr)
1	No containment failure	9.34E-06[2]	8.63E-06[2]
2	Large containment isolation failures	1.23E-08	1.21E-08
3a	Small isolation failures (liner breach)	1.17E-07	1.14E-07
3b	Large isolation failures (liner breach)	2.91E-08	2.83E-08
4	Small isolation failures - failure to seal (type B)	ε[1]	ε[1]
5	Small isolation failures - failure to seal (type C)	ε[1]	ε[1]
6	Containment isolation failures (dependent failure, personnel errors)	ε[1]	ε[1]
7	Severe accident phenomena induced failure (early and late)	1.75E-06	1.97E-06
8	Containment bypass	1.59E-06	1.70E-06
	Total	1.28E-05	1.25E-05

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. Table 5-3 provides population dose for each release category. Table 5-8 provides a correlation of PINGP population dose to 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:

$$EPRI\ Class\ 3a\ Population\ Dose = 10 * 1.75E{+}3 = 1.75E{+}4$$

$$EPRI\ Class\ 3b\ Population\ Dose = 100 * 1.75E{+}3 = 1.75E{+}5$$

Table 5-8 – Baseline Population Doses

Class	Description	Unit 1 Population Dose (person-rem)	Unit 2 Population Dose (person-rem)
1	No containment failure	1.75E+03	1.75E+03
2	Large containment isolation failures	3.40E+06	3.40E+06
3a	Small isolation failures (liner breach)	1.75E+04[1]	1.75E+04[1]
3b	Large isolation failures (liner breach)	1.75E+05[2]	1.75E+05[2]
4	Small isolation failures - failure to seal (type B)	N/A	N/A
5	Small isolation failures - failure to seal (type C)	N/A	N/A
6	Containment isolation failures (dependent failure, personnel errors)	N/A	N/A
7	Severe accident phenomena induced failure (early and late)	3.87E+05	4.31E+05
8	Containment bypass	6.16E+06	6.12E+06

1. 10*L_a
2. 100*L_a

Table 5-9 – Unit 1 Baseline Risk Profile for ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	9.34E-06	72.77%	1.75E+03	1.63E-02
2	Large containment isolation failures	1.23E-08	0.10%	3.40E+06	4.20E-02
3a	Small isolation failures (liner breach)	1.17E-07	0.91%	1.75E+04	2.05E-03
3b	Large isolation failures (liner breach)	2.91E-08	0.23%	1.75E+05	5.10E-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]
7	Severe accident phenomena induced failure (early and late)	1.75E-06	13.62%	3.87E+05	6.77E-01
8	Containment bypass	1.59E-06	12.38%	6.16E+06	9.78E+00
	Total	1.28E-05			1.05E+01

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 to preserve total CDF.

Table 5-10 – Unit 2 Baseline Risk Profile for ILRT

Class	Description	Frequency (/yr)	Contribution (%)	Population Dose (person-rem)	Population Dose Rate (person-rem/yr)
1	No containment failure[2]	8.63E-06	69.27%	1.75E+03	1.51E-02
2	Large containment isolation failures	1.21E-08	0.10%	3.40E+06	4.10E-02
3a	Small isolation failures (liner breach)	1.14E-07	0.91%	1.75E+04	1.99E-03
3b	Large isolation failures (liner breach)	2.83E-08	0.23%	1.75E+05	4.96E-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]
7	Severe accident phenomena induced failure (early and late)	1.97E-06	15.85%	4.31E+05	8.51E-01
8	Containment bypass	1.70E-06	13.64%	6.12E+06	1.04E+01
	Total	1.25E-05			1.13E+01

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 to preserve total CDF.

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).

Risk Impact Due to 10-Year Test Interval

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:

$$Freq_{U1Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF') = \frac{10}{3} * \frac{2}{217} * 1.27\text{E-}5 = 3.90\text{E-}7$$

$$Freq_{U1Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF') = \frac{10}{3} * \frac{.5}{218} * 1.27\text{E-}5 = 9.72\text{E-}8$$

$$Freq_{U2Class3a10yr} = \frac{10}{3} * \frac{2}{217} * (CDF - LERF') = \frac{10}{3} * \frac{2}{217} * 1.24\text{E-}5 = 3.79\text{E-}7$$

$$Freq_{U2Class3b10yr} = \frac{10}{3} * \frac{.5}{218} * (CDF - LERF') = \frac{10}{3} * \frac{.5}{218} * 1.24\text{E-}5 = 9.44\text{E-}8$$

The results of the calculation for a 10-year interval are presented in Table 5-11 abd Table 5-12.

Table 5-11 – Unit 1 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]	9.00E-06	70.11%	1.75E+03	1.58E-02
2	Large containment isolation failures	1.23E-08	0.10%	3.40E+06	4.20E-02
3a	Small isolation failures (liner breach)	3.90E-07	3.04%	1.75E+04	6.83E-03
3b	Large isolation failures (liner breach)	9.72E-08	0.76%	1.75E+05	1.70E-02
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]
7	Severe accident phenomena induced failure (early and late)	1.75E-06	13.62%	3.87E+05	6.77E-01
8	Containment bypass	1.59E-06	12.38%	6.16E+06	9.78E+00
	Total	1.28E-05			1.05E+01

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 to preserve total CDF.

Table 5-12 – Unit 2 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]	8.30E-06	66.61%	1.75E+03	1.45E-02
2	Large containment isolation failures	1.21E-08	0.10%	3.40E+06	4.10E-02
3a	Small isolation failures (liner breach)	3.79E-07	3.05%	1.75E+04	6.64E-03
3b	Large isolation failures (liner breach)	9.44E-08	0.76%	1.75E+05	1.65E-02
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]
7	Severe accident phenomena induced failure (early and late)	1.97E-06	15.85%	4.31E+05	8.51E-01
8	Containment bypass	1.70E-06	13.64%	6.12E+06	1.04E+01
	Total	1.25E-05			1.13E+01

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 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:

$$Freq_{U1Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF') = 5 * \frac{2}{217} * 1.27\text{E-}5 = 5.86\text{E-}7$$

$$Freq_{U1Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF') = 5 * \frac{.5}{218} * 1.27\text{E-}5 = 1.46\text{E-}7$$

$$Freq_{U2Class3a15yr} = \frac{15}{3} * \frac{2}{217} * (CDF - LERF') = 5 * \frac{2}{217} * 1.24\text{E-}5 = 5.69\text{E-}7$$

$$Freq_{U2Class3b15yr} = \frac{15}{3} * \frac{.5}{218} * (CDF - LERF') = 5 * \frac{.5}{218} * 1.24\text{E-}5 = 1.42\text{E-}7$$

The results of the calculation for a 15-year interval are presented in Table 5-13 and Table 5-14.

Table 5-13 – Unit 1 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]	8.76E-06	68.21%	1.75E+03	1.53E-02
2	Large containment isolation failures	1.23E-08	0.10%	3.40E+06	4.20E-02
3a	Small isolation failures (liner breach)	5.86E-07	4.56%	1.75E+04	1.02E-02
3b	Large isolation failures (liner breach)	1.46E-07	1.14%	1.75E+05	2.55E-02
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]
7	Severe accident phenomena induced failure (early and late)	1.75E-06	13.62%	3.87E+05	6.77E-01
8	Containment bypass	1.59E-06	12.38%	6.16E+06	9.78E+00
	Total	1.28E-05			1.06E+01

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 to preserve total CDF.

Table 5-14 – Unit 2 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]	8.06E-06	64.71%	1.75E+03	1.41E-02
2	Large containment isolation failures	1.21E-08	0.10%	3.40E+06	4.10E-02
3a	Small isolation failures (liner breach)	5.69E-07	4.57%	1.75E+04	9.96E-03
3b	Large isolation failures (liner breach)	1.42E-07	1.14%	1.75E+05	2.48E-02
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]
7	Severe accident phenomena induced failure (early and late)	1.97E-06	15.85%	4.31E+05	8.51E-01
8	Containment bypass	1.70E-06	13.64%	6.12E+06	1.04E+01
	Total	1.25E-05			1.13E+01

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 to preserve total CDF.

5.2.4 Step 4 – Determine the Change in Risk in Terms of Internal Events LERF

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 and no equipment in the shield building is credited in the CDF model at PINGP, the ILRT extension does not impact CDF. Therefore, the relevant risk-impact metric is LERF.

For PINGP, 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 10-year test interval from Table 5-11 and Table 5-12, the Class 3b frequency is 9.72E-8/year for Unit 1 and 9.44E-8/year for Unit 2; based on a 15-year test interval from Table 5-13 and Table 5-14, the Class 3b frequency is 1.46E-7/year for Unit 1 and 1.42E-7/year for Unit 2. Thus, the increase in the overall probability of LERF due to Class 3b sequences that is due to increasing the ILRT test interval from 3 to 15 years is 1.17E-7/year for Unit 1 and 1.13E-7/year for Unit 2. Similarly, the increase due to increasing the interval from 10 to 15 years is 4.86E-8/year for Unit 1 and 4.72E-8/year for Unit 2. Table 5-15 summarizes these results.

Table 5-15 – Impact on LERF due to Extended Type A Testing Intervals

ILRT Inspection Interval	Unit 1: 3 Years (baseline)	Unit 1: 10 Years	Unit 1: 15 Years	Unit 2: 3 Years (baseline)	Unit 2: 10 Years	Unit 2: 15 Years
Class 3b (Type A LERF)	2.91E-08	9.72E-08	1.46E-07	2.83E-08	9.44E-08	1.42E-07
ΔLERF (3 year baseline)		6.80E-08	1.17E-07		6.61E-08	1.13E-07
ΔLERF (10 year baseline)			4.86E-08			4.72E-08

As can be seen, even with the conservatisms included in the evaluation (per the EPRI methodology), the estimated change in LERF meets the criteria for a "very small" change when comparing the 15-year results to the current 10-year requirement, as it remains less than 1.0E-7/yr, and meets the criteria for a "small" change when comparing the 15-year results to the original 3-year requirement, as it exceeds 1.0E-7/yr and remains less than a 1.0E-6 change in LERF. For this "small" change in LERF to be acceptable, total LERF must be less than 1.0E-5. The total LERF is calculated below by adding the model Revision 5.3 LERF and change in LERF shown in Table 5-15:

$$\mathrm{LERF} = \mathrm{LERF}_{\mathrm{internal}} + \mathrm{LERF}_{\mathrm{class3Bincrease}}$$

$$\mathrm{LERF}_{\mathrm{U1}} = 2.15\text{E-}7/\mathrm{yr} + 1.17\text{E-}7/\mathrm{yr} = 3.32\text{E-}7/\mathrm{yr}$$

$$\mathrm{LERF}_{\mathrm{U2}} = 1.86\text{E-}7/\mathrm{yr} + 1.13\text{E-}7/\mathrm{yr} = 2.99\text{E-}7/\mathrm{yr}$$

As specified in Regulatory Guide 1.174 [Reference 4], since the total LERF is less than 1.0E-05, it is acceptable for the ΔLERF to be between 1.0E-07 and 1.0E-06.

NEI 94-01 [Reference 1] states that a "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 5-16, the results of this calculation meet the dose rate criteria.

Table 5-16 – Impact on Dose Rate due to Extended Type A Testing Intervals

ILRT Inspection Interval	Unit 1: 10 Years	Unit 1: 15 Years	Unit 2: 10 Years	Unit 2: 15 Years
ΔDose Rate (3 year baseline)	1.609E-02	2.758E-02	1.563E-02	2.680E-02
ΔDose Rate (10 year baseline)		1.149E-02		1.117E-02
%ΔDose Rate (3 year baseline)	0.153%	0.262%	0.138%	0.237%
%ΔDose Rate (10 year baseline)		0.109%		0.099%

1. ΔDose Rate is the difference in the total dose rate between cases. For instance, 'ΔDose Rate (3 year baseline)' for the 1 in 15 case is the total dose rate of the 1 in 15 case minus the total dose rate of the 3 in 10 year case.
2. %ΔDose Rate is the ΔDose Rate divided by the total baseline dose rate. For instance, '%ΔDose Rate (3 year baseline)' for the 1 in 15 case is the 'ΔDose Rate (3 year baseline)' of the 1 in 15 year case divided by the total dose rate of the 3 in 10 year case.

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.

Since CCFP is only concerned with a containment failure and not whether the release is small or large, the Class 1 results without containment spray refinement are used to calculate the CCFP. Table 5-17 shows the steps and results of this calculation.

Table 5-17 – Impact on CCFP due to Extended Type A Testing Intervals

ILRT Inspection Interval	Unit 1: 3 Years (baseline)	Unit 1: 10 Years	Unit 1: 15 Years	Unit 2: 3 Years (baseline)	Unit 2: 10 Years	Unit 2: 15 Years
f(ncf) (/yr)	9.46E-06	9.39E-06	9.34E-06	8.74E-06	8.67E-06	8.63E-06
f(ncf)/CDF	0.737	0.732	0.728	0.702	0.697	0.693
CCFP	0.263	0.268	0.272	0.298	0.303	0.307
ΔCCFP (3 year baseline)		0.530%	0.908%		0.531%	0.910%
ΔCCFP (10 year baseline)			0.378%			0.379%

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 0.908% for Unit 1 and 0.910% for Unit 2. Therefore, this increase is judged to be "small."

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

An estimate of the likelihood and risk implications 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>

- Consistent with the Calvert Cliffs analysis, a half failure is assumed for basemat concealed liner corrosion due to the lack of identified failures (See Table 5-18, Step 1).
- In the 5.5 years following September 1996 when 10 CFR 50.55a started requiring visual inspection, there were three events where a through wall hole in the containment liner was identified. These are Brunswick 2 on 4/27/99, North Anna 2 on 9/23/99, and D. C. Cook 2 in November 1999. The corrosion associated with the Brunswick event is believed to have started from the coated side of the containment liner. Although PINGP has a different containment type, this event could potentially occur at PINGP (i.e., corrosion starting on the coated side of containment). Construction material embedded in the concrete may have contributed to the corrosion. The corrosion at North Anna is believed to have started on the uninspectable side of containment due to wood imbedded in the concrete during construction. The D.C. Cook event is associated with an inadequate repair of a hole drilled through the liner during construction. Since the hole was created during construction and not caused by corrosion, this event does not apply to this analysis. Based on the above data, there are two corrosion events from the 5.5 years that apply to PINGP.
- 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 5-4, 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 5-18, 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 PINGP, the ILRT maximum pressure is 46 psig [References 30 and 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 5.3.1 (See Table 5-18, 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 5-18, Step 4).
- In the Calvert Cliffs analysis, it is noted that approximately 85% of the interior wall surface is accessible for visual inspections. 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 5-18, 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 5-18 – 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 10 CFR 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: 0 Assume a half failure 0.5 / (70 x 5.5) = 1.30E-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	Year	Failure rate
		1 average 5-10 15	2.05E-03 5.19E-03 1.43E-02	1 average 5-10 15	5.13E-04 1.30E-03 3.57E-03
		15 year average = 6.44E-03		15 year average = 1.61E-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.	0.71% (1 to 3 years) 4.14% (1 to 10 years) 9.66% (1 to 15 years)		0.18% (1 to 3 years) 1.04% (1 to 10 years) 2.42% (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	

Table 5-18 – Steel Liner Corrosion Base Case

Step	Description	Containment Cylinder and Dome (85%)	Containment Basemat (15%)
6	Likelihood of non-detected containment leakage (Steps 3 x 4 x 5)	0.00071% (3 years) 0.71% x 1% x 10% 0.00414% (10 years) 4.14% x 1% x 10% 0.00966% (15 years) 9.66% x 1% x 10%	0.00018% (3 years) 0.18% x 0.1% x 100% 0.00104% (10 years) 1.04% x 0.1% x 100% 0.00242% (15 years) 2.42% 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 PINGP.

Table 5-19 – Total Likelihood on Non-Detected Containment Leakage Due to Corrosion for PINGP

Description
At 3 years: 0.00071% + 0.00018% = 0.00089%
At 10 years: 0.00414% + 0.00104% = 0.00517%
At 15 years: 0.00966% + 0.00242% = 0.01207%

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 [Reference 34]. 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. 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 [Reference 34].

5.2.7 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.

PINGP is transitioning to NFPA 805 [Reference 27] licensing basis for fire protection. This transition included performing a Fire PRA and installing modifications to reduce the fire-induced CDF and LERF to those reported in the NFPA 805 LAR. It is anticipated all the NFPA 805 modifications will be completed by the next scheduled ILRT. All the modifications are scheduled to be installed prior to coming out of Unit 1 refueling outage 32 in Autumn 2020; the next scheduled ILRT is Autumn 2022. Therefore, the Fire PRA model is deemed applicable for this calculation.

The Fire PRA model Revision 5.3 was used to obtain the fire CDF and LERF values. To reduce conservatism in the model, the methodology of subtracting existing LERF from CDF is also applied to the Fire PRA model. The Fire PRA model already includes a pre-existing leak basic event, so its contribution to total LERF was not subtracted from the CDF used to find the Class 3 risk (similar to the methodology in Section 5.2.1). Therefore, the portion of LERF removed is the total LERF less the contribution from the pre-existing leak: 9.64E-7 – 5.48E-7 = 4.15E-7 for Unit 1 and 9.27E-7 – 5.49E-7 = 3.78E-7 for Unit 2. The following shows the calculation for Class 3b:

$$Freq_{U1class3b} = P_{class3b} * (CDF - LERF') = \frac{0.5}{218} * (6.64E\text{-}5 - 4.15E\text{-}7) = 1.51\text{E-}7$$

$$Freq_{U1class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF') = \frac{10}{3} * \frac{0.5}{218} * (6.64E\text{-}5 - 4.15E\text{-}7) = 5.04\text{E-}7$$

$$Freq_{U1class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF') = 5 * \frac{0.5}{218} * (6.64E\text{-}5 - 4.15E\text{-}7) = 7.56\text{E-}7$$

$$Freq_{U2class3b} = P_{class3b} * (CDF - LERF') = \frac{0.5}{218} * (6.61E\text{-}5 - 3.78E\text{-}7) = 1.51\text{E-}7$$

$$Freq_{U2class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF') = \frac{10}{3} * \frac{0.5}{218} * (6.61E\text{-}5 - 3.78E\text{-}7) = 5.03\text{E-}7$$

$$Freq_{U2class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF') = 5 * \frac{0.5}{218} * (6.61E\text{-}5 - 3.78E\text{-}7) = 7.54\text{E-}7$$

The 2014 Seismic Reevaluations for operating reactor sites [Reference 29] states the conclusions reached in 2010 by GI-199 [Reference 28] remain valid for estimating Seismic CDF at plants in the Central and Eastern United States, which includes PINGP. EPRI guidance [Reference 29] on recent seismic evaluations states, "EPRI does not recommend using any very conservative approaches to estimate the SCDF such as use of the maximum SCDFs calculated at any one frequency. This type of bounding approach is overly conservative and judged to not provide realistic risk estimates consistent with SCDFs calculated in actual SPRAs." Therefore, the simple average of 1.84E-06 calculated from the reported CDF values in Table D-1 of GI-199 [Reference 28] is used for the Seismic CDF. Since no Seismic LERF value is calculated, it is assumed the LERF/CDF ratio will be similar for seismic risk as for internal events risk. Applying the internal event LERF/CDF ratio to the seismic CDF yields an estimated seismic LERF of 3.07E-8 for Unit 1 and 2.74E-8 for Unit 2, as shown by the equations below.

$$\text{LERF1}_{\text{Seismic}} \approx \text{CDF1}_{\text{Seismic}} * \text{LERF1}_{\text{IE}} / \text{CDF1}_{\text{IE}} = 1.84\text{E-}06 * 2.15\text{E-}7 / 1.28\text{E-}5 = 3.07\text{E-}8$$

$$\text{LERF2}_{\text{Seismic}} \approx \text{CDF2}_{\text{Seismic}} * \text{LERF2}_{\text{IE}} / \text{CDF2}_{\text{IE}} = 1.84\text{E-}06 * 1.86\text{E-}7 / 1.25\text{E-}5 = 2.74\text{E-}8$$

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

$$Freq_{U1class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (1.84E\text{-}6 - 3.07E\text{-}8) = 4.14\text{E-}9$$

$$Freq_{U1class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (1.84E\text{-}6 - 3.07E\text{-}8) = 1.38\text{E-}8$$

$$Freq_{U1class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (1.84E\text{-}6 - 3.07E\text{-}8) = 2.07\text{E-}8$$

$$Freq_{U2class3b} = P_{class3b} * (CDF - LERF) = \frac{0.5}{218} * (1.84E\text{-}6 - 2.74E\text{-}8) = 4.15\text{E-}9$$

$$Freq_{U2class3b10yr} = \frac{10}{3} * P_{class3b} * (CDF - LERF) = \frac{10}{3} * \frac{0.5}{218} * (1.84E\text{-}6 - 2.74E\text{-}8) = 1.38\text{E-}8$$

$$Freq_{U2class3b15yr} = \frac{15}{3} * P_{class3b} * (CDF - LERF) = 5 * \frac{0.5}{218} * (1.84E\text{-}6 - 2.74E\text{-}8) = 2.07\text{E-}8$$

The external event 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 5-20 for Unit 1 and Table 5-21 for Unit 2.

Table 5-20 – Unit 1 PINGP 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	1.55E-07	5.18E-07	7.77E-07	6.22E-07
Internal Events	2.91E-08	9.72E-08	1.46E-07	1.17E-07
Combined	1.85E-07	6.15E-07	9.23E-07	7.38E-07

Table 5-21 – Unit 2 PINGP 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	1.55E-07	5.16E-07	7.75E-07	6.20E-07
Internal Events	2.83E-08	9.44E-08	1.42E-07	1.13E-07
Combined	1.83E-07	6.11E-07	9.16E-07	7.33E-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 increase due to increasing the interval from 10 to 15 years is 3.08E-7 for Unit 1 and 3.05E-7 for Unit 2; the total change in LERF due to increasing the ILRT interval from 3 to 15 years is 7.38E-7 for Unit 1 and 7.33E-7 for Unit 2, which meets the guidance for “small” change in risk, as it exceeds 1.0E-7/yr and remains less than a 1.0E-6 change in LERF. For this change in LERF to be acceptable, total LERF must be less than 1.0E-5. As in Section 5.2.4, the total LERF is calculated below by adding external and internal events LERF and change in LERF:

$$\mathrm{LERF} = \mathrm{LERF_{IE}} + \mathrm{LERF_{fire}} + \mathrm{LERF_{seismic}} + \mathrm{LERF_{class3Bincrease}}$$

$$\mathrm{LERF_{U1}} = 2.15\text{E-}7/\mathrm{yr} + 9.64\text{E-}7/\mathrm{yr} + 3.07\text{E-}8/\mathrm{yr} + 7.38\text{E-}7/\mathrm{yr} = 1.95\text{E-}6/\mathrm{yr}$$

$LERF_{U2} = 1.86E\text{-}7/yr + 9.27E\text{-}7/yr + 2.74E\text{-}8/yr + 7.33E\text{-}7/yr = 1.87E\text{-}6/yr$

Several conservative assumptions were made in this ILRT analysis, as discussed in Sections 4.0, 5.1.3, 5.2.1, and 5.2.4; therefore, the total change in LERF is considered conservative for this application. 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.

5.2.7.1 Other External Hazards

Several “other” external events were evaluated and screened out in the Re-Examination of External Events Evaluation [Reference 32]. As detailed in Section 5.2 of Reference 32, Extreme Winds and Tornadoes are not significant contributors to overall risk impact; therefore, it is screened from consideration. As detailed in Section 5.3 of Reference 32, External Flooding and Intense Precipitation are not significant contributors to overall risk impact; therefore, it is screened from consideration. As detailed in Section 5.4 and 5.5 of Reference 32, other hazards were addressed in assessing the overall risk impact from External Hazards; all these hazards were screened from consideration.

5.2.8 Defense-In-Depth Impact

Regulatory Guide 1.174, Revision 3 [Reference 4] describes an approach that is acceptable for developing risk-informed applications for a licensing basis change that considers engineering issues and applies risk insights. One of the considerations included in RG 1.174 is Defense in Depth. Defense in Depth is a safety philosophy that employs successive compensatory measures to prevent accidents or mitigate damage if a malfunction, accident, or naturally caused event occurs at a nuclear facility. The following seven considerations as presented in RG 1.174, Revision 3, Section C.2.1.1.2 will serve to evaluate the proposed licensing basis change for overall impact on Defense in Depth.

1. <u>Preserve a reasonable balance among the layers of defense.</u>

The use of the risk metrics of LERF, population dose, and conditional containment failure probability collectively ensures the balance between prevention of core damage, prevention of containment failure, and consequence mitigation is preserved. The change in LERF is “small” with respect to internal events and “small” when including external events per RG 1.174, and the change in population dose and CCFP are “small” as defined in this analysis and consistent with NEI 94-01 Revision 3-A.

2. <u>Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.</u>

The adequacy of the design feature (the containment boundary subject to Type A testing) is preserved as evidenced by the overall “small” change in risk associated with the Type A test frequency change.

3. <u>Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.</u>

The redundancy, independence, and diversity of the containment subject to the Type A test is preserved, commensurate with the expected frequency and consequences of challenges to the system, as evidenced by the overall “small” change in risk associated with the Type A test frequency change.

4. <u>Preserve adequate defense against potential CCFs.</u>

Adequate defense against CCFs is preserved. The Type A test detects problems in the containment which may or may not be the result of a CCF; such a CCF may affect failure of another portion of containment (i.e., local penetrations) due to the same phenomena. Adequate defense against CCFs is preserved via the continued performance of the Type B and C tests and the performance of inspections. The change to the Type A test, which bounds the risk associated with containment failure modes including those involving CCFs, does not degrade adequate defense as evidenced by the overall “small” change in risk associated with the Type A test frequency change.

5. Maintain multiple fission product barriers.

Multiple Fission Product barriers are maintained. The portion of the containment affected by the Type A test extension is still maintained as an independent fission product barrier, albeit with an overall “small” change in the reliability of the barrier.

6. Preserve sufficient defense against human errors.

Sufficient defense against human errors is preserved. The probability of a human error to operate the plant, or to respond to off-normal conditions and accidents is not significantly affected by the change to the Type A testing frequency. Errors committed during test and maintenance may be reduced by the less frequent performance of the Type A test (less opportunity for errors to occur).

7. Continue to meet the intent of the plant’s design criteria.

The intent of the plant’s design criteria continues to be met. The extension of the Type A test does not change the configuration of the plant or the way the plant is operated.

5.3 Sensitivities

5.3.1 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 5-22 – Table 5-27. Since CCFP is only concerned with a containment failure and not whether the release is small or large, the Class 1 results without containment spray refinement is used to calculate the CCFP. The Annual Dose Rate calculations are performed using the containment spray adjustments. 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 5-22 – Unit 1 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)
Corrosion Likelihood X 1	2.91E-08	9.72E-08	1.46E-07	6.80E-08	1.17E-07	4.86E-08
Corrosion Likelihood X 1000	2.94E-08	1.02E-07	1.63E-07	7.28E-08	1.34E-07	6.11E-08
Corrosion Likelihood X 10000	3.17E-08	1.47E-07	3.22E-07	1.16E-07	2.90E-07	1.74E-07
Corrosion Likelihood X 100000	5.51E-08	6.00E-07	1.91E-06	5.45E-07	1.85E-06	1.31E-06

Table 5-23 – Unit 2 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)
Corrosion Likelihood X 1	2.83E-08	9.44E-08	1.42E-07	6.61E-08	1.13E-07	4.72E-08
Corrosion Likelihood X 1000	2.86E-08	9.93E-08	1.59E-07	7.07E-08	1.30E-07	5.94E-08
Corrosion Likelihood X 10000	3.08E-08	1.43E-07	3.13E-07	1.12E-07	2.82E-07	1.69E-07
Corrosion Likelihood X 100000	5.35E-08	5.83E-07	1.85E-06	5.29E-07	1.80E-06	1.27E-06

Table 5-24 – Unit 1 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)
Corrosion Likelihood X 1	2.63E-01	2.68E-01	2.72E-01	5.30E-03	9.08E-03	3.78E-03
Corrosion Likelihood X 1000	2.63E-01	2.69E-01	2.72E-01	5.35E-03	9.16E-03	3.82E-03
Corrosion Likelihood X 10000	2.63E-01	2.69E-01	2.73E-01	5.77E-03	9.89E-03	4.12E-03
Corrosion Likelihood X 100000	2.65E-01	2.75E-01	2.82E-01	1.00E-02	1.72E-02	7.15E-03

Table 5-25 – Unit 2 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)
Corrosion Likelihood X 1	2.98E-01	3.03E-01	3.07E-01	5.31E-03	9.10E-03	3.79E-03
Corrosion Likelihood X 1000	2.98E-01	3.04E-01	3.07E-01	5.35E-03	9.18E-03	3.82E-03
Corrosion Likelihood X 10000	2.98E-01	3.04E-01	3.08E-01	5.78E-03	9.91E-03	4.13E-03
Corrosion Likelihood X 100000	3.00E-01	3.10E-01	3.17E-01	1.00E-02	1.72E-02	7.16E-03

Table 5-26 – Unit 1 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)
Corrosion Likelihood X 1	6.89E-03	2.30E-02	3.45E-02	1.61E-02	2.76E-02	1.15E-02
Corrosion Likelihood X 1000	6.96E-03	2.32E-02	3.48E-02	1.62E-02	2.78E-02	1.16E-02
Corrosion Likelihood X 10000	7.51E-03	2.50E-02	3.75E-02	1.75E-02	3.00E-02	1.25E-02
Corrosion Likelihood X 100000	1.30E-02	4.34E-02	6.51E-02	3.04E-02	5.21E-02	2.17E-02

Table 5-27 – Unit 2 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)
Corrosion Likelihood X 1	6.70E-03	2.23E-02	3.35E-02	1.56E-02	2.68E-02	1.12E-02
Corrosion Likelihood X 1000	6.76E-03	2.25E-02	3.38E-02	1.58E-02	2.70E-02	1.13E-02
Corrosion Likelihood X 10000	7.30E-03	2.43E-02	3.65E-02	1.70E-02	2.92E-02	1.22E-02
Corrosion Likelihood X 100000	1.27E-02	4.22E-02	6.33E-02	2.95E-02	5.06E-02	2.11E-02

5.3.2 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 [Reference 24]. 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 5-28 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 5-28 – PINGP Summary of ILRT Extension Using Expert Elicitation Values (from Reference 24)

Leakage Size (L_a)	Expert Elicitation Mean Probability of Occurrence	Percent Reduction
10	3.88E-03	86%
100	2.47E-04	91%

Taking the baseline analysis and using the values provided in Table 5-11 – Table 5-14 for the expert elicitation sensitivity yields the results in Table 5-29 for Unit 1 and Table 5-30 for Unit 2.

Table 5-29 – PINGP Unit 1 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	9.49E-06	9.44E-06	1.75E+03	1.65E-02	9.31E-06	1.63E-02	9.23E-06	1.61E-02
2	1.23E-08	1.23E-08	3.40E+06	4.20E-02	1.23E-08	4.20E-02	1.23E-08	4.20E-02
3a	N/A	4.93E-08	1.75E+04	8.63E-04	1.64E-07	2.88E-03	2.47E-07	4.31E-03
3b	N/A	3.14E-09	1.75E+05	5.49E-04	1.05E-08	1.83E-03	1.57E-08	2.75E-03
7	1.75E-06	1.75E-06	3.87E+05	6.77E-01	1.75E-06	6.77E-01	1.75E-06	6.77E-01
8	1.59E-06	1.59E-06	6.16E+06	9.78E+00	1.59E-06	9.78E+00	1.59E-06	9.78E+00
Totals	1.28E-05	1.28E-05	1.01E+07	1.05E+01	1.28E-05	1.05E+01	1.28E-05	1.05E+01
ΔLERF (3 per 10 yrs base)	N/A				7.32E-09		1.26E-08	
ΔLERF (1 per 10 yrs base)	N/A				N/A		5.23E-09	
CCFP	26.12%				26.17%		26.21%	

Table 5-30 – PINGP Unit 2 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	8.77E-06	8.72E-06	1.75E+03	1.53E-02	8.60E-06	1.51E-02	8.52E-06	1.49E-02
2	1.21E-08	1.21E-08	3.40E+06	4.10E-02	1.21E-08	4.10E-02	1.21E-08	4.10E-02
3a	N/A	4.79E-08	1.75E+04	8.39E-04	1.60E-07	2.80E-03	2.40E-07	4.19E-03
3b	N/A	3.05E-09	1.75E+05	5.34E-04	1.02E-08	1.78E-03	1.53E-08	2.67E-03
7	1.97E-06	1.97E-06	4.31E+05	8.51E-01	1.97E-06	8.51E-01	1.97E-06	8.51E-01
8	1.70E-06	1.70E-06	6.12E+06	1.04E+01	1.70E-06	1.04E+01	1.70E-06	1.04E+01
Totals	1.25E-05	1.25E-05	1.01E+07	1.13E+01	1.25E-05	1.13E+01	1.25E-05	1.13E+01
ΔLERF (3 per 10 yrs base)	N/A				7.12E-09		1.22E-08	
ΔLERF (1 per 10 yrs base)	N/A				N/A		5.08E-09	
CCFP	29.61%				29.67%		29.71%	

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.

5.3.3 RCP Seal Sensitivity

Open Finding SY-A17-01 was not closed by the F&O closure team because the N9000 RCP seal with Abeyance had not been approved by the NRC (see Section A.2 for details). PINGP applied the seal model using the guidance of WCAP-16175-P-A and, as discussed in the 10 CFR 50.69 LAR, addressed the NRC SE limitations and conditions for applying a Combustion Engineering (CE) seal model to a non-CE plant [Reference 40]. However, the seal package includes an optional abeyance seal which actuates after failure of the three normally operating RCP seal stages, and there is no NRC SE for the modeling or failure probability of the abeyance seal package. For the Surveillance Frequency Control Program (SCFP) LAR [Reference 41], PINGP performed a sensitivity evaluation that removed credit for the abeyance seal. A similar sensitivity is performed here. Internal events and fire risk are shown in Table 5-31 and Table 5-32. Similar to the results of the sensitivity evaluation documented in the SFCP LAR, internal events risk increased no more than 5.5% and fire risk increased no more than 2.5%.

Table 5-31 – Internal Events Results with Abeyance Failed

Top Event	Baseline	Abeyance Failed	Delta	Percent Change
U1 CDF	1.28E-05	1.33E-05	4.4E-07	3.4%
U1 LERF	2.15E-07	2.18E-07	3.4E-09	1.6%
U2 CDF	1.25E-05	1.31E-05	6.8E-07	5.5%
U2 LERF	1.86E-07	1.91E-07	5.1E-09	2.7%

Table 5-32 – Fire PRA Results with Abeyance Failed

Top Event	Baseline	Abeyance Failed	Delta	Percent Change
U1 CDF	6.64E-05	6.72E-05	8.5E-07	1.3%
U1 LERF	9.64E-07	9.71E-07	7.8E-09	0.8%
U2 CDF	6.61E-05	6.78E-05	1.7E-06	2.5%
U2 LERF	9.27E-07	9.41E-07	1.4E-08	1.5%

Using these new CDF and LERF values and the ILRT extension analysis methodology detailed in Sections 5.2.1 – 5.2.4 yields the following sensitivity results.

Table 5-33 – RCP Seal Sensitivity: Unit 1 PINGP 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	1.57E-07	5.25E-07	7.87E-07	6.30E-07
Internal Events	3.02E-08	1.01E-07	1.51E-07	1.21E-07
Combined	1.88E-07	6.25E-07	9.38E-07	7.50E-07

Table 5-34 – RCP Seal Sensitivity: Unit 2 PINGP 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	1.59E-07	5.29E-07	7.94E-07	6.35E-07
Internal Events	2.99E-08	9.97E-08	1.49E-07	1.20E-07

Table 5-34 – RCP Seal Sensitivity: Unit 2 PINGP 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	
Combined	1.89E-07	6.29E-07	9.43E-07	7.55E-07

As discussed in Section 5.2.7, this meets the guidance for “small” change in risk, as the change in LERF exceeds 1.0E-7/yr and remains less than a 1.0E-6. For this change in LERF to be acceptable, total LERF must be less than 1.0E-5. Using the methodology detailed in Section 5.2.7, total U1 LERF is 1.97E-6; total U2 LERF is 1.91E-6. 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. Therefore, modeling the abeyance seal has no impact on the conclusion of the ILRT extension analysis risk evaluation.

6.0 RESULTS

The Internal Events results from this ILRT extension risk assessment for PINGP are summarized in Table 6-1 for Unit 1 and Table 6-2 for Unit 2.

Table 6-1 – Unit 1 ILRT Extension Summary (Internal Events)

Class	Dose (person-rem)	Base Case 3 in 10 Years		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year
1	1.75E+03	9.34E-06	1.63E-02	9.00E-06	1.58E-02	8.76E-06	1.53E-02
2	3.40E+06	1.23E-08	4.20E-02	1.23E-08	4.20E-02	1.23E-08	4.20E-02
3a	1.75E+04	1.17E-07	2.05E-03	3.90E-07	6.83E-03	5.86E-07	1.02E-02
3b	1.75E+05	2.91E-08	5.10E-03	9.72E-08	1.70E-02	1.46E-07	2.55E-02
7	3.87E+05	1.75E-06	6.77E-01	1.75E-06	6.77E-01	1.75E-06	6.77E-01
8	6.16E+06	1.59E-06	9.78E+00	1.59E-06	9.78E+00	1.59E-06	9.78E+00
Total		**1.28E-05**	**1.05E+01**	**1.28E-05**	**1.05E+01**	**1.28E-05**	**1.06E+01**
ILRT Dose Rate from 3a and 3b							
ΔTotal Dose Rate (Person-Rem/Year)	From 3 Years	N/A		1.609E-02		2.758E-02	
	From 10 Years	N/A		N/A		1.149E-02	
%ΔDose Rate	From 3 Years	N/A		0.153%		0.262%	
	From 10 Years	N/A		N/A		0.109%	
3b Frequency (LERF/Year)							
ΔLERF	From 3 Years	N/A		6.80E-08		1.17E-07	
	From 10 Years	N/A		N/A		4.86E-08	
CCFP %							
ΔCCFP%	From 3 Years	N/A		0.530%		0.908%	
	From 10 Years	N/A		N/A		0.378%	

Table 6-2 – Unit 2 ILRT Extension Summary (Internal Events)

Class	Dose (person-rem)	Base Case 3 in 10 Years		Extend to 1 in 10 Years		Extend to 1 in 15 Years	
		CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year	CDF/Year	Person-Rem/Year
1	1.75E+03	8.63E-06	1.51E-02	8.30E-06	1.45E-02	8.06E-06	1.41E-02
2	3.40E+06	1.21E-08	4.10E-02	1.21E-08	4.10E-02	1.21E-08	4.10E-02
3a	1.75E+04	1.14E-07	1.99E-03	3.79E-07	6.64E-03	5.69E-07	9.96E-03
3b	1.75E+05	2.83E-08	4.96E-03	9.44E-08	1.65E-02	1.42E-07	2.48E-02
7	4.31E+05	1.97E-06	8.51E-01	1.97E-06	8.51E-01	1.97E-06	8.51E-01
8	6.12E+06	1.70E-06	1.04E+01	1.70E-06	1.04E+01	1.70E-06	1.04E+01
Total		**1.25E-05**	**1.13E+01**	**1.25E-05**	**1.13E+01**	**1.25E-05**	**1.13E+01**
ILRT Dose Rate from 3a and 3b							
ΔTotal Dose Rate (Person-Rem/Year)	From 3 Years	N/A		1.563E-02		2.680E-02	
	From 10 Years	N/A		N/A		1.117E-02	
%ΔDose Rate	From 3 Years	N/A		0.138%		0.237%	
	From 10 Years	N/A		N/A		0.099%	
3b Frequency (LERF/Year)							
ΔLERF	From 3 Years	N/A		6.61E-08		1.13E-07	
	From 10 Years	N/A		N/A		4.72E-08	
CCFP %							
ΔCCFP%	From 3 Years	N/A		0.531%		0.910%	
	From 10 Years	N/A		N/A		0.379%	

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 “small” changes in risk as resulting in increases of CDF greater than 1.0E-6/year and less than 1.0E-5/year and increases in LERF greater than 1.0E-7/year and less than 1.0E-6/yr. 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 1.17E-7/year for Unit 1 and 1.13E-7/year for Unit 2 using the EPRI guidance; this value increases negligibly if the risk impact of corrosion-induced leakage of the steel liners occurring and going undetected during the extended test interval is included. Total Internal Events LERF (baseline and change in LERF due to the ILRT extension) is 3.32E-7 for Unit 1 and 2.99E-7 for Unit 2. Therefore, the estimated change in LERF is determined to be “small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. Considering the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 4.86E-8/year for Unit 1 and 4.72E-8/year for Unit 2, the risk increase is “very small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4].
- When external event risk is included, 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 7.38E-7/year for Unit 1 and 7.33E-7/year for Unit 2 using the EPRI guidance, and total LERF is 1.95E-6/year for Unit 1 and 1.87E-6/year for Unit 2. As such, the estimated change in LERF is determined to be “small” using the acceptance guidelines of Regulatory Guide 1.174 [Reference 4]. The risk change resulting from a change in the Type A ILRT test interval from 3 in 10 years to 1 in 15 years bounds the 1 in 10 years to 1 in 15 years risk change. When external event risk is included, the increase in LERF resulting from a change in the Type A ILRT test interval from 1 in 10 years to 1 in 15 years is estimated as 3.08E-7/year for Unit 1 and 3.05E-7/year for Unit 2, and the total LERF is 1.52E-6 /year for Unit 1 and 1.45E-6/year for Unit 2. Therefore, the risk increase is “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 0.028 person-rem/year for Unit 1 and 0.027 person-rem/year for Unit 2. NEI 94-01 [Reference 1] states that a “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 0.908% for Unit 1 and 0.910% for Unit 2. NEI 94-01 [Reference 1] states that increases in CCFP of ≤ 1.5% is “small.” Therefore, this increase is judged to be “small.”

Therefore, increasing the ILRT interval to 15 years is considered to be “small” since it represents a small change to the PINGP risk profile.

Previous Assessments

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 conclusions for PINGP confirm these general conclusions on a plant-specific basis considering the severe accidents evaluated for PINGP, the PINGP containment failure modes, and the local population surrounding PINGP.

A. PRA ACCEPTABILITY

A.1. PRA Quality Statement for Permanent 15-Year ILRT Extension

Revision 5.3 of the PINGP PRA model is the most recent evaluation of internal event risk. The PINGP PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the PINGP PRA is based on the single top fault tree methodology, which is a well-known PRA methodology in the industry.

The PRA models [References 17 and 18] have been assessed against RG 1.200 [Reference 36]. The internal events PRA model was subject to a full-scope peer review conducted in accordance with RG 1.200 [Reference 36] in November 2010. The internal flooding portion of the PRA model was not available for peer review at that time. Subsequently, a focused scope peer review was performed on the internal flooding portions of the internal events PRA model against RG 1.200 [Reference 36] in September 2012. An additional focused scope peer review of the internal events PRA model was conducted in May 2014 to evaluate the model changes made to address the incorporation of Flowserve N9000 Reactor Coolant Pump seals against RG 1.200 [Reference 36].

The Fire PRA model was subject to a full-scope peer review conducted in accordance with RG 1.200 [Reference 36] in May 2012. Additionally, two focused scope peer reviews against RG 1.200 [Reference 36] have been conducted to review changes to the Fire PRA model. The first was conducted in November 2013 and reviewed the upgrade to the correlations used in determining hot gas layer temperatures. The second was conducted in December 2017 and reviewed the apportioning of the main control board fire frequency and the implementation of NUREG/CR-6850 thermal response time to cable damage.

Finding closure reviews were conducted on the Internal Events, including Internal Flooding, and Fire PRA models in October 2017 [Reference 35]. Dispositioned findings were reviewed and closed using the process documented in Appendix X to NEI 05-04, NEI 07-12 and NEI 12-13, “Close-Out of Facts and Observations” [Reference 33]. Following this initial review, there were eight outstanding Findings. A focused scope peer review [Reference 42], discussed above, reviewed and closed one outstanding Finding (FSS-B2-01). An additional closure review was performed April 30 to May 1, 2019. Following the completion of this closure review session, five Findings that were examined were determined to be closed [Reference 37]. This closure review did not address Finding SY-A17-01, which remains open. Reference 39 contains the finding information for SY-A17-01, which is discussed in Section A.2. The F&O Closure Review process and closure team makeup for the initial closure review was previously described in NSPM Response to Request for Additional Information for adoption TSTF-425 [Reference 41]. The process for the second closure review was equivalent to the first but with a smaller team due to the lower number of findings.

Northern States Power Company, a Minnesota corporation, (NSPM) employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all operating NSPM nuclear generation sites. 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 the NSPM approach to PRA model maintenance, as it applies to the PINGP PRA.

A.1.1 PRA Maintenance and Update

The NSPM risk management process ensures that the applicable PRA models used in this application continue to reflect the as-built and as-operated plant. The process delineates the

responsibilities and guidelines for updating the PRA models, and includes criteria for both regularly scheduled and interim PRA model updates. The process includes provisions for monitoring potential areas affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, and industry operational experience), for assessing the risk impact of unincorporated changes, and for controlling the model and associated computer files. The process will assess the impact of these changes on the plant PRA model in a timely manner which is typically considered to be once every two refueling outages.

A.2. Prairie Island Open Finding

F&O Number: SY-A17-01
Applicable Supporting Requirement: SY-A17

Upgrade? No

New Method: Yes

Closure Status: Open

F&O Text:
Subsection 1.8.1 of AC System notebook, "PRA-PI-SY-AC, Rev. 2.1a" indicates safeguards 4kV buses do not result in RCP trip. Failure in both 4Kv buses (bus 15 and 16) which is a cause of 1AC requires RCP trip to prevent RCP seal failure, but 1N9-SBO gate does not include the operator action.

Cause(s) of loss of 1AC which do not result in RCP trip requires RCP trip within 2 hours to prevent RCP LOCA.

Actions to Address Finding:
Evaluation of condition was performed and documented in PRA Folder:

V.SPA.14.013 (Sensitivity Analysis for Fail to Trip RCPs on Loss of 4kV Safeguard Bus), - Rev 0

The results presented in V.SPA.14.013 - Section 6.3 present the maximum risk increase that could occur if operator action to trip RCPs was required but did not occur for SBO sequences that occur after a loss of 4kV safeguard bus. The potential risk increase, 7.42E-09 for CDF on Unit 1 and 9.46E-09 for CDF on Unit 2, is small. Furthermore, the analysis presented in V.SPA.14.013 takes no credit for operator action to trip the RCPs. Given the simplicity of the action required, time available to perform action, presence of alarms that would indicate RCP seal cooling failure, and the time available, there is a reasonable probability that operator action to trip RCPs would be successful. This, along with the low risk values, shows that the issue identified by F&O SY-A17-01 represents a negligible source of uncertainty for the base PRA model.

Accident Sequence Notebook (PRA-PI-AS-2.2)) Updates:

Added Transient Event Tree assumption 12 to clearly identify that all SBO sequences are assumed to begin with offsite power failed. Also included in assumption 12 is a discussion on scenarios involving loss of safeguards AC power which do not result in RCP trip and the negligible risk impact of not modeling the operator action to perform trip based on the calculation performed in V.SPA.14.013. This item resolves F&O SY-A17-01.

Uncertainty Notebook (PRA-PI-UN-2.2) Updates:

Added Transient Event Tree assumption 12 (from AS Notebook Section 5.1.1) discussion to table AS-1

Acceptability Evaluation:

Reviewed V.SPA.14.013, Sensitivity Analysis for Fail to Trip RCPs on Loss of 4kV Safeguard Bus. This analysis was used to show that failure to trip the RCP with a loss of all 4kv safety buses would not be risk significant. The sensitivity shows that the issue identified by F&O SY-A17-01 represents a negligible source of uncertainty for the base PRA model and does not significantly affect the plant CDF. The resolution of this F&O did not involve an actual change to the plant model. Instead, an assumption was added to the Accident Sequence Notebook that RCPs would trip during most SBO events due to loss of all safety and non-safety buses.

Since the FLOWSERVE N9000 RCP SEAL MODEL has not been approved by the NRC this F&O cannot be closed. If the FLOWSERVE model is approved than this F&O can be closed.

Impact on ILRT Extension:
The analysis in V.SPA.14.013 showed failure to trip the RCP with a loss of all 4kv safety buses would not be risk significant, the sensitivity shows that the issue identified by F&O SY-A17-01 represents a negligible source of uncertainty for the base PRA model, and it is expected that this F&O finding can be considered to be closed once the underlying RCP seal model has been approved [Reference 38]. Although not related to this specific F&O, a similar sensitivity evaluation to that performed in the Surveillance Frequency Control Program (SFCP) LAR [Reference 41] was performed in Section 5.3.3. The sensitivity evaluation demonstrates the impact of removing credit for the “abeyance” seal on the LERF risk metrics for the change in ILRT test frequency to once every 15 years; the results of this sensitivity evaluation verify credit for the “abeyance” seal does not change the conclusion of the ILRT extension analysis. Therefore, there is no impact on the ILRT extension analysis.